ENERGEAN OIL & GAS PLC

אנרג'יאן נפט וגז פי אל סי

("החברה")

<u>מסמך רישום</u>

רישום למסחר בבורסה לניירות ערך בתל אביב בע"מ ("**הבורסה**" או "**הבורסה בתל אביב**") של עד 152,823,238 מניות רגילות בנות 0.01 לירת שטרלינג ע"נ כ"א רשומות על שם, עד 174,138 מניות רגילות בנות 0.01 לירה שטרלינג ע"נ כ"א, אשר החברה התחייבה להנפיק לחברת HIL Hydrocarbon Investments Ltd ("**HIL**") ולחברת Capital Energy Investments Ltd ("**CEI**") כמתואר בסעיף 3.1 להלן ועד 659,050 מניות רגילות בנות 0.01 לירה שטרלינג ע"נ כ"א, אשר ינבעו כתוצאה ממימוש 659,050 אופציות לרכישת מניות שהוענקו לעובדי החברה.

מניותיה הרגילות של החברה רשומות למסחר ברשימה הראשית של בורסת לונדון:[1]

סימן ניירות הערך של החברה בבורסת לונדון הינו: ENOG.

סימן ניירות הערך בבורסה בתל-אביב הינו: אנאג.

מניות החברה תירשמנה למסחר לפי הוראות פרק ה' 3 לחוק ניירות ערך, התשכ"ח-1968, ולפיכך דיווחי החברה יהיו בשפה האנגלית ותוכנם יהיה בהתאם למתכונת הדיווח שלה באנגליה. כמו כן, כללי האחריות החלים על החברה ביחס לחובות הדיווח שלה עלולים להיות לפי הדין האנגלי.

ניתן יהיה לסחור במניות החברה בבורסה בתל אביב רק החל מיום 29 באוקטובר 2018.

תאריך: 15 באוקטובר 2018

[1] The premium listing segment of the Official List of the UK Financial Conduct Authority (the "**FCA**").

תוכן עניינים

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1. תשקיף החברה מיום 16 במרץ 2018
2. דו"ח שנתי לשנה שהסתיימה ביום 31 בדצמבר 2017 ("דו"ח שנתי 2017")
3. דיווחים מאז הדו"ח השנתי 2017

חלק ראשון

המפורט במסמך רישום זה להלן ובטבלת השוואת הדינים מהווה סקירה כללית אשר אין בכוונתה להוות סקירה ממצה או פרשות מוסמכת של הדין ואין בה כדי לשמש תחליף לעיון במסמכי ההתאגדות ו/או לקבלת ייעוץ מקצועי אחר לרבות ייעוץ משפטי בנוגע לדיני אנגליה. בנוסף יודגש כי הסקירה שלהלן אינה סוקרת את חוקי אנגליה העוסקים בניירות ערך, לרבות כללי ה- UK Financial Conduct Authority, את כללי הבורסה לניירות ערך בלונדון (ה- London Stock Exchange) או כל מקור נורמטיבי אחר החל או העשוי לחול על החברה ועל בעלי מניותיה.

1. **התאגיד**

1.1. **שם התאגיד**: אנרג'יאן נפט וגז פי אל סי Energean Oil & Gas plc, מספר רישום 10758801.

1.2. **מקום ההתאגדות**: החברה התאגדה על פי דיני אנגליה תחת ה- Companies Act 2006 ("**חוק החברות האנגלי**"). החברה אינה כפופה לדיני החברות בישראל ואינה מאמצת הוראות מכח חוב החברות, התשנ"ט – 1999.

1.3. **תאריך ההתאגדות**: 8 במאי 2017.

1.4. **סוג ניירות הערך שהנפיק התאגיד**: מניות רגילות בנות 0.01 לירת שטרלינג ע"נ כ"א.

1.5. **הבורסה בה רשומות מניות החברה למסחר**: בורסת לונדון.

1.6. **מניות החברה נרשמו לראשונה למסחר בבורסת לונדון ביום**: 21 במרץ 2018.

1.7. **ניתן יהיה לסחור במניות החברה בבורסה בתל אביב החל מיום**: 29 באוקטובר 2018.

2. **מידע על התאגיד**

2.1. **פרטי מען החברה**:

מען רשום: Energean Oil & Gas plc, 3rd Floor, Accurist House, 44 Baker Street, London W1U 7AL, United Kingdom

טלפון: +44 (0) 203 655 7200

פקס: +44 (0) 203 655 7299

2.2. **סימון ניירות הערך של החברה**:

בבורסת לונדון: ENOG.

בבורסה בתל אביב: אנאג.

2.3. **אנשי קשר**:

איש קשר עם גופי הפיקוח והאכיפה של הדין הזר:

השם: **Michelle Churchward**

מען רשום: Energean Oil & Gas plc, 3rd Floor, Accurist House, 44 Baker Street, London W1U 7AL, United Kingdom

טלפון: +44 (0) 203 655 7200

פקס: +44 (0) 203 655 7299

<u>איש קשר של החברה עם רשות ניירות ערך</u>:

השם: שלומי לוי, רו"ח

מען: רחוב מצדה 9, מגדל ב.ס.ר., קומה 21, בני ברק

טלפון: 1188 779 (3) 972+

פקס: 1185 779 (3) 972+

<u>מען החברה להמצאת כתבי בית דין בישראל</u>**:**

מען: רחוב מצדה 9, מגדל ב.ס.ר., קומה 21, בני ברק

טלפון: 1188 779 (3) 972+

פקס: 1185 779 (3) 972+

3. **<u>תיאור המניות</u>**

3.1. **<u>כללי</u>**

לחברה אין הון מניות רשום. כל הון מניות החברה הנרשם למסחר הונפק ונפרע במלואו. נכון ליום 15 באוקטובר 2018, הון מניות המונפק של החברה עומד על 152,823,238 מניות רגילות רשומות על שם בנות 0.01 לירה שטרלינג ע"נ כ"א. נכון למועד בקשה זאת, לחברה אין מניות רדומות.

3.2. **<u>מספר המניות הרגילות אשר תירשמנה למסחר בבורסה</u>**

152,823,238 מניות רגילות בנות 0.01 לירה שטרלינג ע"נ כ"א רשומות על שם ("**המניות לרישום**"), כן עד 174,138 מניות רגילות בנות 0.01 לירה שטרלינג ע"נ כ"א, אשר יונפקו כתוצאה ממימוש ההתחייבויות שניתנו ל HIL ול-CEI ובנוסף עד 659,050 מניות רגילות בנות 0.01 לירה שטרלינג ע"נ כ"א, אשר יונפקו כתוצאה ממימוש 659,050 אופציות לא רשומות למסחר שהוענקו לעובדי החברה (יחדיו, "**מניות האופציה**"). המניות לרישום אינן נושאות הוראות חסימה על מכירה חוזרת והינן חופשיות למסחר ללא מגבלות על סחירותן. המניות שינבעו כתוצאה ממימוש מניות האופציה לא יישאו הוראות חסימה על מכירה חוזרת ויהיו חופשיות למסחר, ללא מגבלות על סחירותן.

ב-30 ביוני 2017, במסגרת הסכם רה-ארגון אשר נחתם בין החברה לבין בעלי המניות של אנרג'יאן אי אנד פי אחזקות (לרבות HIL ו-CEI, כבעלי מניות), אנרג'יאן אי אנד פי אחזקות, אנרג'יאן ישראל ואנרג'יאן אינטרנשיונל ("**הסכם הרה-ארגון**"), הפכה החברה לחברת החזקות של קבוצת אנרג'יאן. במסגרת הסכם הרה-ארגון, החברה הסכימה לרכוש את כל הון המניות המונפק של אנרג'יאן אי אנד פי אחזקות בתמורה להנפקה של 65,468,982 מניות לחלק מבעלי המניות הקיימים בתמורה להעברה של 99.7% מהון המניות המונפק של חברת אנרג'יאן אי אנד פי אחזקות לחברה וכן התחייבות להנפקה של כ - 174,138 מניות נוספות לחברת HIL ולחברת CEI (שתיהן בעלות מניות של החברה עובר להסכם הרה-ארגון) בתמורה להעברה של יתרת 0.3% מהון המניות המונפק של חברת אנרג'יאן אי אנד פי אחזקות באותם התנאים של הסכם הרה-ארגון ("**מניות HIL ו-CEI**"). יצוין כי מניות HIL ו-CEI לא הועברו במסגרת הסכם הרה-ארגון בשל שעבוד שחל עליהן וכי עד שיוסר השעבוד, מניות HIL ו-CEI מוחזקות בנאמנות לטובת החברה. החברה, HIL וכן CEI פועלים להסרת השעבוד.

הבורסה בתל אביב הסכימה לרשום את ניירות הערך נושא מסמך הרישום למסחר בה.

3.3. **<u>הוראות סעיף 346ב לחוק ניירות ערך תשכ"ח-1968 ("חוק ניירות ערך")</u>**

כל עוד מניות החברה רשומות למסחר בבורסה, תהיה החברה כפופה להוראות סעיף 346ב לחוק ניירות ערך, ככל שאלו יחולו על החברה. נכון למועד מסמך רישום זה, החברה לא אימצה "גלולת רעל".

3.4. **<u>הוראות סעיף 39א לחוק ניירות ערך</u>**

במידה ומניות החברה יימחקו ממסחר בבורסה בלונדון, וכל עוד מניותיה יהיו רשומות למסחר בבורסה, תפעל החברה בהתאם להוראות סעיף 39א לחוק ניירות ערך.

3.5. **<u>אחריות בעלי המניות</u>**

אחריותם של בעלי המניות לחובות החברה מוגבלת לפירעון הסכום אשר התחייבו לשלם עבור המניות שהוקצו להם ואשר טרם שולם.

3.6. **<u>הזכויות הצמודות למניות</u>**

3.6.1. הון מניותיה של החברה מורכב ממניות רגילות בנות 0.01 לירה שטרלינג ע"נ.

3.6.2. לכל מניה קול אחד (1) בהצבעה באסיפה הכללית.

3.6.3. לכל מניה מוצמדות, בין היתר, הזכויות הבאות:

3.6.3.1. הזכות לקבל הודעה על האסיפה הכללית של החברה;

3.6.3.2. הזכות להשתתף ולהצביע באסיפה הכללית של החברה;

3.6.3.3. הזכות לקבל את הדוחות הכספיים של החברה; וכן -

3.6.3.4. הזכות לקבל דיבידנד במידה ויוכרז.

3.6.4. במקרה שהחברה שלחה בקשה למידע מבעלי מניותיה או למי שככל הנראה יש לו עניין אישי במניות החברה בהתאם לחוק האנגלי בדבר עניין אישי זה, ובעל המניות לא מסר את מידע הנדרש ממנו בזמן הקבוע בחוק האנגלי או שדירקטוריון החברה מאמין כי בעל המניות או אותו אדם מסר מידע חלקי או מטעה, רשאי דירקטוריון החברה לשלול את זכויות השתתפות וההצבעה באסיפה הכללית של אותו בעל המניות או אדם.

3.7. **<u>תעודות מניה</u>**

3.7.1. כל אדם הרשום במרשם בעלי המניות כבעל מניות יהיה זכאי, ללא תשלום, במסגרת הזמן שנקבעה בחוק, לקבל תעודה אחת עבור כל המניות, בעלות אותו סוג, המוחזקות על ידו. לעניין מגבלות מכוח הוראות סעיף 46ב לחוק ניירות ערך, ראה סעיף 3.3 לעיל.

3.8. **<u>רווחים וחלוקת רווחים</u>**

3.8.1. <u>חלוקת דיבידנד</u>

3.8.1.1. בכפוף להוראות חוק החברות האנגלי, החברה יכולה להורות על חלוקת דיבידנדים לבעלי מניותיה בהחלטה של בעלי המניות שהתקבלה ברוב רגיל, וזאת בתנאי שסכום החלוקה לא יחרוג מהסכום שקבע דירקטוריון החברה.

3.8.1.2. בכפוף להוראות חוק החברות האנגלי, הדירקטוריון יכול לשלם דיבידנד ביניים או דיבידנד בסכום קבוע אם הוא סבור שרווחי החברה המותרים לחלוקה מצדיקים זאת.

3.8.1.3. דיבידנדים או כספים אחרים הניתנים לחלוקה לבעלי המניות לא יישאו ריבית למעט אם נקבע אחרת בזכות הצמודה למניה.

3.8.1.4. הדירקטוריון רשאי להקפיא תשלום דיבידנד לבעל מניות שלא מסר את מידע הנדרש ממנו בהתאם לבקשה לקבלת מידע תחת חוק החברות האנגלי כאמור בסעיף 3.6.4 לעיל,

שנשלחה אליו על ידי החברה או שדירקטוריון החברה מאמין כי אותו בעל מניות מסר מידע חלקי או מטעה.

3.8.1.5. הדירקטוריון רשאי להציע לכל בעל מניות את הזכות לקבל מניות שנפרעו ושולמו במקום מזומן ביחס לדיבידנד שהוכרז, כולו או חלקו, אם הוסמך לכך על ידי החלטה של בעלי המניות החברה שהתקבלה ברוב רגיל. חלוקה כאמור תהיה בכפוף להוראות מסלקת הבורסה והדין החל על החברה כפי שיחולו מעת לעת.

3.8.1.6. הדירקטוריון יכול לבטל דיבידנד שהוכרז ולא נתבע במשך 12 שנים.

3.8.1.7. לוחות הזמנים לחלוקת דיבידנד יהיו בהתאם להוראות סעיף 4 פרק ט' לחלק השני של חוקי העזר של מסלקת הבורסה, אשר נכון ליום זה הינם כדלקמן:

(א) הודעה על תשלום דיבידנד במזומן ועל היום הקובע לתשלום של חברה אשר אין לה ניירות ערך המירים הרשומים למסחר, תתקבל בבורסה לפחות 5 ימי מסחר לפני היום הקובע.

(ב) הודעה על תשלום דיבידנד במזומן ועל היום הקובע לתשלום של חברה אשר יש לה ניירות ערך המירים הרשומים למסחר, תתקבל בבורסה לפחות 8 ימי מסחר לפני היום הקובע.

(ג) חברה המחלקת דיבידנד במזומן, תודיע לפחות 2 ימי מסחר לפני יום התשלום את שיעור הדיבידנד לכל מניה.

(ד) מועד תשלום דיבידנד במזומן יהיה כדלקמן: (1) תשלום דיבידנד אשר הטיפול בניכוי המס בגינו מתבצע על ידי המנפיק, יבוצע בין היום השנים עשר ליום השמונה עשר שלאחר היום הקובע לתשלום; (2) תשלום דיבידנד אשר הטיפול בניכוי המס בגינו אינו מתבצע על ידי המנפיק, יבוצע בין יום המסחר החמישי שלאחר היום הקובע לתשלום ליום השמונה עשר שלאחר היום הקובע לתשלום.

3.8.1.8. התשלום לבעלי המניות הרגילות שיחזיקו במניות החברה דרך חברי הבורסה יבוצע בדולר ארה"ב.

3.9. **<u>הפחתת הון</u>**

3.9.1. בכפוף להוראות חוק החברות האנגלי, החברה רשאית להפחית את ההון המונפק של החברה בהחלטה מיוחדת של בעלי המניות ובאישור בית המשפט הגבוה באנגליה.

3.10. **<u>הזכויות בעת פירוק וארגון מחדש של החברה</u>**

3.10.1. לפי חוק חדלות פירעון האנגלי (1986), במקרה של פירוק החברה, המפרק יהיה רשאי באישור שיתקבל על ידי החברה בהחלטה מיוחדת של בעלי המניות או כל אישור אחר הנדרש לעניין, וכן:

3.10.1.1. לחלק בעין בין בעלי המניות את כלל או חלק מנכסי החברה, ויכול, לעניין זה, להעריך כל נכס ולקבוע כיצד תתבצע החלוקה בין בעלי המניות שונים או סוגי מניות שונים (לעניין מגבלות מכוח הוראות סעיף 246ב לחוק ניירות ערך, ראה סעיף 3.3 לעיל);

3.10.1.2. להפקיד בנאמנות לטובת בעלי המניות את כל או חלק מנכסי החברה; וכן -

3.10.1.3. לקבוע את הכללים לפיהם יוחזקו נכסי החברה בנאמנות ואת היקפה.

בעל מניה לא יחויב לקבל נכס שמוצמדת אליו חבות מכל סוג שהיא.

3.10.2. כוחו של מפרק יהיה יפה לעניין מכירה מלאה או חלקית של נכסי החברה בעבור מניות, אגרות חוב או התחייבויות אחרות של תאגיד אחר, אף אם הוקם במיוחד למטרת ביצוע המכירה.

3.11. **<u>מינוי דירקטורים</u>**

3.11.1. מספר חברי הדירקטוריון לא יפחת משני (2) דירקטורים, למעט אם נקבע אחרת על ידי האסיפה הכללית.

3.11.2. חברי הדירקטוריון יכולים להתמנות על ידי האסיפה הכללית, על ידי הדירקטוריון, ואם בעת המינוי מכהן רק דירקטור אחד, על ידי אותו דירקטור.

3.11.3. בכל אסיפה כללית שנתית יפרשו כל הדירקטורים שמונו על ידי הדירקטוריון או על ידי הדירקטור היחיד כאמור לעיל.

3.11.4. היה והחברה לא בחרה אדם כלשהו למלא את מושב הדירקטוריון שהתפנה, יראו בדירקטור שפרש כנבחר מחדש על ידי בעלי המניות למעט אם: (1) האסיפה הכללית החליטה לא למלא את המושב שהתפנה או (2) בחירתו המחודשת של הדירקטור עלתה להצבעה לא קיבלה את אישור האסיפה הכללית.

3.11.5. אדם שאינו דירקטור שפרש לא ימונה לדירקטור באסיפה הכללית של החברה למעט אם:

3.11.5.1. מועמדותו הומלצה על ידי הדירקטוריון; או

3.11.5.2. הודעה של בעל מניות הזכאי להשתתף ולהצביע באסיפה הכללית של החברה (שאינו המועמד עצמו לכהונה) על כוונתו להעמיד לבחירה מועמד לכהונה כדירקטור (או לכהונה נוספת), הכוללת את הפרטים הנדרשים כקבוע בתקנון החברה, נמסרה לחברה בתקופה שאינה עולה על 42 ימים ואינה קצרה משבעה ימים לפני התאריך שנקבע לאסיפה.

3.11.6. האסיפה הכללית יכולה לפטר כל אחד מחברי הדירקטוריון בכל עת בהחלטה של בעלי המניות שהתקבלה ברוב רגיל.

3.11.7. דירקטור אינו חייב להחזיק במניות החברה.

3.12. **<u>סמכויות הדירקטוריון והאצלת סמכויות</u>**

3.12.1. הדירקטוריון יכול להאציל מסמכויותיו לוועדה המורכבת מדירקטורים או דירקטור יחיד, ותחת תנאים מסוימים, להאציל מסמכויותיו גם לוועדה שאינה מורכבת כולה מדירקטורים.

3.12.2. הדירקטוריון יכול להקים דירקטוריונים מקומיים כדי שאלו ינהלו את ענייני החברה במקום גיאוגרפי מסוים, למנות דירקטורים שיכהנו באותם דירקטוריונים מקומיים וכן לקבוע את תגמולם. הדירקטוריון רשאי להאציל מסמכויותיו לחברי הדירקטוריון המקומי ולהותיר להם להאציל את הסמכויות שהואצלו להם לגורמים אחרים.

3.13. **<u>האסיפה הכללית</u>**

3.13.1. <u>אסיפה שנתית</u>

3.13.1.1. דירקטוריון החברה יכנס והחברה תקיים אסיפות כלליות שנתיות כנדרש על פי חוק.

3.13.1.2. הוראות תקנון החברה העוסקות באסיפות כלליות של החברה, יחולו, בשינויים המחויבים, על כל אסיפה כללית נפרדת של בעלי מניות המחזיקים סוג מניה, למעט שיכולו ההוראות הבאות:

(א) המניין הדרוש הינו שני אנשים בעלי זכות להצביע בנושא הנדון.

(ב) כל בעל מניות המחזיק בסוג המניה המיוצגת באסיפה או מיוצג באמצעות מיופה כוח, יכול לדרוש קיום הצבעה על דרך ספירת מניות.

(ג) לכל בעל מניות המחזיק בסוג המניה המיוצגת באסיפה המוכרעת בדרך של ספירת קולות יהיה קול אחד בהצבעה עבור מניה אחת.

לעניין מגבלות מכוח הוראות סעיף 346ב לחוק ניירות ערך, ראה סעיף 3.3 לעיל.

3.13.2. <u>אסיפה מיוחדת</u>

3.13.2.1. דירקטוריון החברה רשאי לכנס אסיפה כללית בכל מועד, זמן ומקום שיקבע.

3.13.2.2. דירקטוריון החברה יכנס אסיפה כללית על פי דרישת בעלי המניות הזכאים לכך, והכל בכפוף להוראות חוק החברות האנגלי ותקנון החברה.

3.13.3. <u>זימון אסיפה</u>

3.13.3.1. כל בעל מניות או מספר בעלי מניות המחזיק או מחזיקים לפחות 10% מזכויות ההצבעה בחברה רשאים לבקש זימון של אסיפה כללית מיוחדת.

3.13.3.2. כל דירקטור בחברה רשאי לכנס אסיפה כללית במקרה שמניין הדירקטורים הנמצאים באנגליה אינו מספיק לשם כינוסה, אולם במידה ואין דירקטור אשר יש לו היכולת או במידה ואין דירקטור המוכן לכנס אסיפה כללית, רשאים כל שני בעלי מניות בחברה לזמן אסיפה לצורך מינוי דירקטור או דירקטורים כדי שאלו יזמנו את האסיפה הכללית.

3.13.3.3. הודעת זימון לאסיפה כללית השנתית תימסר לא יאוחר מ- 21 ימים לפני תאריך האסיפה. בכפוף להוראות חוק החברות האנגלי, כל הודעת זימון לאסיפה שאינה אסיפה כללית שנתית תימסר לא יאוחר מ- 14 ימים לפני תאריך האסיפה.

3.13.3.4. ההודעה תפרט האם מדובר באסיפה כללית שנתית או אסיפה מיוחדת, את המועד, השעה, המקום, הנושאים שלשמם נתכנסה האסיפה והרוב הנדרש לאישורם וכן, אם ניתן, אופן ההשתתפות באסיפה באמצעות אמצעים אלקטרוניים.

3.13.3.5. בכפוף להוראות חוק החברות האנגלי, להוראות תקנון החברה וההגבלות המוטלות על כל מניה באשר היא, הודעה על זימון אסיפה תימסר לכל בעל מניות הרשום במרשם בעלי המניות של החברה (למעט בעלי מניות שאינם זכאים לקבל הודעה מהחברה) בסוף יום העסקים שיקבע על ידי דירקטוריון החברה, אשר לא יהיה יותר משבעה (7) ימים טרם יום משלוח ההודעה.

3.13.3.6. לצורך קביעת בעלי המניות הזכאים להשתתף ולהצביע באסיפה ואופן ההצבעה, על החברה לפרט בהודעת הזימון מועד שלא יאוחר מ-48 שעות לפני מועד קיום האסיפה (לא כולל ימי מנוחה) בו חייב בעל מניות להיות רשום במרשם בעלי המניות של החברה כדי להיות זכאי להשתתף ולהצביע באסיפה או כדי למנות מיופה כוח מטעמו.

3.13.4. <u>השתתפות באסיפה</u>

3.13.4.1. דירקטוריון החברה רשאי לאפשר לבעלי מניות הזכאים להשתתף באסיפה הכללית, להשתתף על ידי שימוש באמצעים אלקטרונים. בעלי המניות להם יאושר להשתתף באסיפה באמצעות אמצעים אלקטרונים, יחשבו כנוכחים לצורך המניין הנדרש לקיום האסיפה וכן יהיו זכאים להשתתף ולהצביע באסיפה.

3.13.4.2. אם לאחר מסירת הודעת הזימון לכינוס האסיפה אך טרם התכנסותה (בין אם נדרשת החברה למסור הודעה נוספת בדבר קיום האסיפה נדחית ובין או לאו), סבור הדירקטוריון כי זה בלתי סביר או אין זה מעשי, מטעמים שלא בשליטתו, לקיים את האסיפה במקום הנקבע לה, רשאי הדירקטוריון לשנות את מקום האסיפה ו/או לדחות את המועד שנקבע

לאסיפה, ולא יהיה צורך במסירת הודעה חדשה בדבר האסיפה. נדחתה אסיפה כאמור, נדרש דירקטוריון החברה, ככל שהדבר אפשרי, לפרסם את המועד, השעה והמקום החדש של האסיפה לפחות בשני עיתונים בעלי תפוצה ארצית וכן לדאוג למסירת ההודעה בדבר שינוי המקום או השעה ו/או דחיית האסיפה.

3.13.4.3. דירקטוריון החברה, ובכל אסיפה כללית, יו"ר האסיפה כללית רשאים:

(א) לאסור כניסתו של אדם המסרב לציית להוראות, הדרישות והמגבלות שנקבעו.

(ב) להוציא ממקום האסיפה כל אדם המפריע להתנהלות האסיפה.

3.13.4.4. <u>הליך ההצבעה באסיפות כלליות של החברה</u>:

הצבעת מחזיקי מניות בבורסה בתל אביב באסיפות הכלליות של החברה תעשה בהתאם להוראות סעיף 7א. בפרק ט"ו1 לחלק ב' של חוקי העזר של מסלקת הבורסה, כפי שיעודכנו מעת לעת, ואלו עיקריהן נכון למועד הגשת מסמך רישום זה:

(א) החברה תגיש למסלקת הבורסה בסמוך לאחר פרסום ההודעה לציבור על האסיפה בקשה לטיפול בהצבעה בה יפורט מועד האסיפה, היום הקובע להשתתפות באסיפה, המועד האחרון בו ניתן להזין הוראות הצבעה באסיפה הכללית למערכות של בנק היורוקליר והמועד האחרון להגשת הוראות הצבעה למסלקת הבורסה להשתתפות באסיפה בנוסח המצורף לחוקי העזר של מסלקת הבורסה.

(ב) החברה תודיע לחברי מסלקת הבורסה כי ההצבעה באסיפה כאמור תתבצע באמצעות המסלקה וכן מהו המועד האחרון בו ניתן להגיש הוראת הצבעה למסלקה להשתתפות באסיפה.

(ג) חבר מסלקה המבקש כי מסלקת הבורסה תצביע בשם ניירות הערך הרשומים לזכותו במסלקה, ימסור למסלקה עד השעה 14:00 ביום המסחר שלפני היום בו חל המועד האחרון בו ניתן להזין הוראות הצבעה במערכות של בנק היורוקליר, הוראות הצבעה.

(ד) חבר יגיש למסלקה הוראה אחת בלבד בגין כל ניירות הערך עבורם מבקש החבר כי המסלקה תצביע בשמו. הוראת ההצבעה תכלול חלוקה של כמות ניירות הערך בהתאם להצבעתם - בעד, נגד ונמנע. סך כל הכמות המופיעה בהוראת ההצבעה שניתנה על ידי החבר לא תעלה על היתרה בפועל של נייר הערך הרשומה במסלקה לזכות החבר ביום הקובע לאסיפה.

3.13.5. <u>מניין חוקי</u>

3.13.5.1. האסיפה הכללית לא תקבל שום החלטה ו/או הליך ללא נוכחותו של מניין חוקי. היעדרו של מניין חוקי לא יימנע את בחירתו או מינויו של יו"ר האסיפה, אשר לא יחשב כנושא לדיון באסיפה. בכפוף לחריגים הקבועים בתקנון, המניין החוקי לקיום האסיפה הכללית הוא נוכחות של לפחות שני בעלי מניות להם הזכות להצביע על הנושאים שידונו באסיפה.

3.13.5.2. אם (1) לא יהיה מניין חוקי בתוך חמש דקות ממועד שנקבע בהודעת הזימון (או זמן ארוך יותר שלא יעלה על 30 דקות שקבע יו"ר האסיפה) או (2) המניין החוקי חדל מלהתקיים, האסיפה תדחה למועד ולמקום שייקבע יו"ר האסיפה, למעט אם האסיפה זומנה לבקשת בעלי מניות (במקרה כזה האסיפה תבוטל).

3.13.5.3. כל אדם הזכאי להשתתף ולהצביע באסיפה הנדחית יהווה את המניין החוקי הדרוש לקיום האסיפה הנדחית. אם לא יהיה מניין חוקי בתוך 15 דקות מהמועד שנקבע לאסיפה הנדחית, האסיפה תבוטל.

3.13.6. <u>קבלת החלטות</u>

3.13.6.1. בהתאם להוראות חוק החברות האנגלי, אלא אם נקבע אחרת, החלטות האסיפה הכללית יתקבלו ברוב רגיל של לפחות 50% מקולות בעלי המניות הזכאים להצביע.

3.13.6.2. בהתאם להוראות חוק החברות האנגלי החלטות האסיפה הכללית יתקבלו ברוב של לפחות 75% מקולות של בעלי המניות הזכאים להצביע , בין היתר, במקרים הבאים:

(א) תיקון התקנון;

(ב) שינוי שם;

(ג) רישום מחדש של חברה ציבורית כחברה פרטית;

(ד) לבטל או לשנות את זכות הקדימה הקבוע בחוק החברות האנגלי ולהעניק לדירקטוריון סמכות כללית לבטל או לשנות זכות זו;

(ה) שינוי זכויות הצמודות למניה או לסוג מניה (באסיפת סוג);

(ו) הפחתת הון באישור בית המשפט;

(ז) אישור הסכם לרכישה חוזרת של מניות החברה שלא דרך הבורסה; וכן -

(ח) החלטות מסוימות הנוגעות לפירוק החברה.

3.13.6.3. בכפוף לזכויות או למגבלות הצמודות למניות ובכפוף לזכויות ולמגבלות שפורטו בהודעת הזימון:

(א) לכל בעל מניות הנוכח באסיפה יהיה קול אחד.

(ב) בכפוף לסעיף (ג) להלן, לכל מיופה כוח שמונה באופן חוקי על ידי בעל מניות אחד או מספר בעלי מניות, יהיה קול אחד.

(ג) מיופה כוח אחד יכול להצביע גם בעד החלטה וגם נגד החלטה במקרים הבאים:

i. מיופה הכוח מונה באופן חוקי על ידי יותר מבעל מניות אחד; וכן -

ii. (א) מיופה הכוח הונחה על ידי אחד או יותר מבעלי המניות שמינו אותו להצביע בעד ההחלטה וגם הונחה על ידי אחד או יותר משאר בעלי המניות שמינו אותו להצביע נגד ההחלטה או (ב) הונחה על ידי אחד או יותר מבעלי המניות שמינו אותו להצביע בעד או נגד ההחלטה וגם הונחה על ידי אחד או יותר משאר בעלי המניות שמינו אותו להצביע בהתאם לשיקול דעתו.

3.13.6.4. ליו"ר האסיפה לא יהיה את הקול המכריע במקרה של שוויון קולות בהצבעה.

3.13.6.5. חמישה בעלי מניות המייצגים לפחות 10% מזכויות ההצבעה בחברה זכאים לדרוש הצבעה על דרך ספירת מניות באסיפה הכללית של החברה.

3.13.6.6. במקרה של הצבעה על דרך ספירת מניות ובכפוף לזכויות או למגבלות הצמודות למניות, לכל בעל מניות או מיופה כוחו יהיה קול אחד עבור כל מניה אחת אותה מחזיק אותו בעל מניות.

3.13.6.7. במקרה של מחזיקי מניות משותפים, הצבעתו של הבכיר מבניהם תהא זו שתתקבל, בין אם הצביע בעצמו ובין אם הצביע באמצעות מיופה כוח. מעמדו של בעל המניות הבכיר יקבע בהתאם לסדר שמות בעלי המניות כפי שאלו רשומים במרשם בעלי המניות של החברה.

3.13.6.8. למעט אם דירקטוריון החברה קבע אחרת, בעל מניות לא יהיה רשאי להצביע באסיפה כללית או באסיפה סוג, בעצמו או באמצעות מיופה כוח, אם המניות המוחזקות על ידו לא נפרעו במלואן.

3.14. **<u>העברת מניות</u>**

3.14.1. בעל מניות רשאי להעביר את תעודת מניה באמצעות כל כתב העברה או באמצעות כתב העברה שאושר על-ידי הדירקטוריון. כתב ההעברה יהיה חתום על-ידי או בשמו של המעביר, ולמעט אם המנייה נפרעה במלואה, גם על ידי הנעבר. המעביר יישאר הבעלים של המניה עד שיעודכן שמו של הנעבר במרשם בעלי המניות של החברה. יצוין שכל מניות החברה אשר רישומן למסחר מתבקש נפרעו במלואן.

3.14.2. כל המניות שאינן מונפקות באמצעות תעודות מניה, יועברו באופן אלקטרוני באמצעות מערכת ה-CREST, למעט אם חוק החברות האנגלי קובע אחרת.

3.14.3. הדירקטוריון רשאי, לשיקול דעתו הבלעדי, לסרב לרשום העברה של תעודת מניה שלא נפרעה במלואה, בהינתן שהסירוב לא מונע מסחר במניות החברה מלהתקיים באופן חופשי ונאות. הדירקטוריון רשאי לסרב לרשום העברה של תעודת מניה, למעט אם כתב ההעברה:

3.14.3.1. נרשם ונחתם (אם ניתן לחתימה על ידי חותם), במשרד או מקום אחר שנקבע על ידי הדירקטוריון בצירוף התעודה המתייחסת לאותה המניה וראיות אחרות שהדירקטוריון יכול לדרוש באופן סביר כדי להוכיח את זכות המעביר לבצע את ההעברה;

3.14.3.2. הוא ביחס לסוג אחד של מניות; ו-

3.14.3.3. נעשה לזכותם של לא יותר מארבעה בני אדם.

3.14.4. אם הדירקטוריון מסרב להעביר תעודת מניה, הודעת הסירוב תשלח למעביר בתוך חודשיים מהיום שהתבקשה ההעברה להירשם בספרי החברה.

3.14.5. לא ייגבה סכום לטיפול בהעברת מניות.

3.14.6. בכפוף לתקנות ה- CREST, הדירקטוריון יכול לקבוע כי מניה או סוג מניות יונפקו ללא תעודה ושהעברתן של מניות מאותו הסוג תעשה באמצעות מערכת אלקטרונית.

3.14.7. אם ניתנה הודעה לבעל מניות המעביר מניה שלאחר מכאן הועברה, אז הנעבר יהיה כפוף לאותה הודעה המניה אם ההודעה ניתנה לאותו אדם לפני שרישום המניה על שם הנעבר התבצעה במרשם המניות.

3.15. **<u>חובות גילוי של בעלי מניות מהותיים בחברה</u>**

3.15.1. בעל מניות בחברה חייב להודיע לחברה על כל שינוי בהחזקותיו הישירות או העקיפות במניות החברה כאשר בעל המניות מגיע להחזקה השווה, גבוהה או נמוכה מ-3% מהון מניות החברה. כמו כן, כל בעל המניות המחזיק למעלה מ-3% במניות החברה ("**בעל מניות מהותי**") חייב להודיע לחברה על כל שינוי בהחזקותיו של לפחות אחוז אחד במניות החברה. החברה תדווח על הודעה שקיבלה כאמור מבעל מניות מהותי או בעל מניות שהפך להיות בעל מניות מהותי לכל המאוחר ביום המסחר באנגליה העוקב ליום קבלת ההודעה. החברה תודיע על הגדלה או הפחתה בזכויות ההצבעה הכלליות והון החברה בסוף כל חודש קלנדרי וכן בסוף יום העסקים באנגליה העוקב לשינוי מהותי הנובע מעסקה שביצעה החברה.

3.16. **<u>הנפקת מניות</u>**

3.16.1. בכפוף להוראות חוק החברות האנגלי, לזכות הקדימה הקבועה בו ומבלי לגרוע מזכויותיהם של בעלי המניות, החברה רשאית להנפיק מניות בעלות זכויות או מגבלות שייקבעו בהחלטה של בעלי המניות שהתקבלה ברוב רגיל או, במקרים מסוימים, בהתאם להחלטת הדירקטוריון (לעניין מגבלות מכוח הוראות סעיף 46ב לחוק ניירות ערך, ראה סעיף 3.3 לעיל).

3.16.2. לדירקטוריון הסמכות להקצות מניות וזכויות לקבלת ניירות ערך המירים למניות החברה ואת הסמכות להמיר ניירות ערך למניות בחברה, עד לסכום הנומינלי המצטבר הקבוע לתקופה בחוק החברות האנגלי.

3.16.3. בכפוף להוראות חוק החברות האנגלי, מבלי לפגוע בזכויות כלשהן הצמודות למניות או סוג מניות, ניתן להנפיק מניות בנות פדיון או מניות שאינן בנות פדיון, אשר יהיו ניתנות לפדיון לאופציית החברה או מחזיק המניה. הדירקטוריון רשאי לקבוע את התנאים ואופן פדיון המניות, ובלבד שיעשה זאת טרם הקצאתן.

3.17. **<u>שיפוי וביטוח</u>**

3.17.1. <u>ביטוח</u>

3.17.1.1. הדירקטוריון רשאי לבטח כל מי שמכהן בהווה או כיהן בעבר בחברה בתפקידים הבאים:

(א) דירקטור, נושא משרה או עובד של החברה או כל גוף שהוא או שהיה חברת האם או הבת של החברה או גוף שלחברה, לחברת האם או הבת של החברה יש בו עניין, ישיר או עקיף, או גוף שהחברה, חברת האם או הבת, מקושרת או מסונפת אליו.

(ב) נאמן קרן הפנסיה של העובדים או של כל גוף מהמנויים בסעיף לעיל, אשר יש לו עניין ישיר או עקיף בחברה.

3.17.1.2. דירקטור או מי שחדל לכהן כדירקטור לא יהיה אחראי כלפי החברה או בעלי מניותיה בהקשר להטבה שניתנה בהתאם לתקנון. קבלת הטבה כאמור לא תפסול אדם מלשמש כדירקטור בחברה.

3.17.1.3. הדירקטוריון רשאי לרכוש ביטוח, על חשבון החברה, לכל נושא משרה של החברה.

3.17.2. <u>שיפוי</u>

3.17.2.1. בכפוף להוראות חוק החברות האנגלי, אך מבלי לגרוע מכל שיפוי לו זכאי אדם בחברה, ישופה כל דירקטור או נושא משרה בחברה (למעט רואה החשבון המבקר של החברה) מתוך נכסי החברה במקרים הבאים:

(א) כל חבות שנגרמה לו בגין רשלנות, מחדל, הפרת חובה או הפרת אמונים בקשר לענייני החברה או חברות הבנות שלה;

(ב) כל חבות שנגרמה לו במסגרת הליכים משפטיים אזרחיים או פליליים, בהם ניתן פסק דין לטובתו, שהוא זוכה בהם או שהם הסתיימו מבלי לקבוע אשם או מבלי שנדרש להודות בהפרה של חובה מהותית שהוא חב כדירקטור או נושא משרה; וכן -

(ג) כל חבות אחרת שנגרמה בגין חובותיו ותפקידו בחברה ובחברות הבנות שלה.

3.18. **<u>רכישת כפויה</u>**

3.18.1. תחת חוק החברות האנגלי, אדם אשר הציע לרכוש את כל מניות החברה כך שלאחר ההצעה הוא יחזיק ב- 90% ממניות החברה ("**המציע**"), יכול לכפות את הרכישה על שאר בעלי המניות המחזיקים את ה-10% הנותרים ממניות החברה ("**בעלי המניות הנותרים**"). המציע ישלח הודעה לבעלי המניות הנותרים

בדבר הרכישה הכפויה ולאחר שישה שבועות יישלח הודעה לחברה הכוללת את כתב העברת המניות הנותרות על שמו. החברה תחתום על כתב ההעברה בשם בעלי המניות הנותרים והמציע ישלם את התמורה והיא תחזיק את התמורה בנאמנות על שם בעלי המניות הנותרים. באופן כללי, על התמורה הניתנת לבעלי המניות הנותרים להיות זהה לתמורה שניתנה לשאר בעלי המניות בהצעת הרכש המקורית, למעט אם בעל מניות נותר יכול להראות שהתמורה אינה הוגנת.

3.19. **<u>הצטרפות למכירה</u>**

3.19.1. חוק החברות האנגלי מאפשר, בנסיבות מסוימות, לבעל מניות מיעוט את הזכות להצטרף למכירת המניות לאדם שהציע לרכוש את מניות החברה. אם הוגשה הצעת רכש לכלל מניות החברה ובכל זמן לפני סוף התקופה שנקבעה בהצעת הרכש, המציע החזיק או הסכים להחזיק 90% ממניות החברה, יכול כל בעל מניות שאליו הופנתה ההצעה, אשר לא קיבל את ההצעה, להודיע למציע בכתב על קבלת ההצעה. המציע נדרש לשלוח הודעה לכל בעל מניות אשר לו הזכות להצטרפות למכירה בתוך חודש מיום שזכות ההצטרפות נוצרה. המציע רשאי לקבוע מגבלת זמן על מימוש זכות ההצטרפות של בעלי מניות המיעוט, ואולם תקופה זו אינה יכולה להסתיים לפני המאוחר מבין שלושה חודשים מהמועד האחרון לקבלת הצעת הרכש, או שלושה חודשים מהמועד בו ניתנה ההודעה לבעלי המניות הנותרים על זכותם להצטרף למכירה. אם בעל מניות ממש את זכותו להצטרף למכירה, המציע חייב לרכוש את המניות באותם התנאים שהוצעו בהצעה המקורית, או בתנאים אחרים שיוסכמו בין הצדדים.

4. **<u>המסחר במניות החברה בבורסת לונדון ותיאור הליך העברת ניירות הערך בין הבורסה לבורסת לונדון ולהיפך</u>**

העברת המניות בין הבורסה לבין הבורסה בלונדון ולהיפך תעשה בהתאם להוראות הקבועות בחוקי העזר של מסלקת הבורסה. יצוין כי המניות יועברו מה- CREST לחשבון מסלקת הבורסה בבנק היורוקליר, והמסלקה תנהל מרשם מקביל אשר ישקף את מספר המניות בחשבון המסלקה בנק היורוקליר.

5. **<u>מיסוי</u>**

כמקובל בעת קבלת החלטות על השקעות בכספים, יש לשקול את השלכות המס הקשורות בהשקעה בניירות הערך הכלולים במסמך הרישום. ההוראות הכלולות במסמך הרישום או בנספחיו בדבר מיסוי ניירות הערך אינן מתיימרות להוות פרשנות מוסמכת של הוראות הדין הרלוונטיות, ואינן באות במקום ייעוץ מקצועי, בהתאם לנתונים המיוחדים ולנסיבות הייחודיות לכל משקיע ולכן מומלץ לפנות לקבלת ייעוץ מקצועי בהתאם לנתונים של כל משקיע. האמור להלן מבוסס על הדין והפרקטיקה החלים בישראל, נכון למועד מסמך רישום זה, אשר כפופים לשינויים ולפרשנויות שונות. המידע ניתן בדרך של סיכום כללי בלבד ואינו <u>מתיימר</u> להיות ניתוח מקיף של השלכות המס החלות על בעלי מניות בחברה, ויתכן כי לא יחול על סוגים מסוימים של בעלי מניות, כגון סוחרים בניירות ערך או מי שפעילותו בניירות ערך עולה כדי עסק, אשר יתכן כי יהיו כפופים לדינים מיוחדים. יתר על כן, האמור להלן מתייחס אך ורק לבעלי מניות המחזיקים במניות רגילות כהשקעה, ואשר הינם בעלי הזכות שביושר הסופיים למניות אלו ולתקבולים הנובעים מהן. פרק זה עוסק אך ורק בהשלכות המס בישראל ובבריטניה אלא אם צוין במפורש אחרת.

5.1. **<u>מיסוי ישראלי</u>**

5.1.1. לפי הדין הקיים נכון למסמך רישום זה חלות על ניירות הערך הכלולים במסמך הרישום הסדרי המס המתוארים בתמצית להלן:

5.1.1.1. <u>רווח הון ממכירת ניירות הערך המוצעים</u>

(א) לפי לסעיף 91 לפקודה, רווח הון ריאלי ממכירת ניירות ערך על-ידי יחיד תושב ישראל חייב במס בשיעור המס השולי של היחיד בהתאם לסעיף 121 לפקודה, אך בשיעור שלא יעלה על 25%, ויראו את רווח ההון כשלב הגבוה ביותר בסולם הכנסתו החייבת. זאת, למעט לגבי מכירת ניירות ערך על-ידי יחיד שהינו "בעל מניות מהותי" בחברה, קרי,

המחזיק, במישרין או בעקיפין, לבדו או יחד עם אחר (כהגדרת המונח בפקודה), בעשרה אחוזים (10%) לפחות באחד או יותר מאמצעי השליטה (כהגדרת המונח בפקודה) בחברה - במועד מכירת ניירות הערך או במועד כלשהו ב-12 החודשים שקדמו למכירה כאמור. שיעור המס לגבי רווח הון ריאלי של בעל מניות מהותי יהיה בשיעור שלא יעלה על 30%.

(ב) כמו כן, לגבי יחיד שתבע הוצאות ריבית ריאלית והפרשי הצמדה בשל ניירות הערך, יחויב רווח ההון ממכירת ניירות הערך במס בשיעור של עד 30%, וזאת עד לקביעת הוראות ותנאים לניכוי הוצאות ריבית ריאלית לפי סעיף 101א(א)(9) לפקודה. שיעור המס המופחת כאמור לא יחול לגבי יחיד שההכנסה בידיו ממכירת ניירות הערך היא בגדר הכנסה מ"עסק", בהתאם להוראות סעיף 2(1) לפקודה שאז, יחויב היחיד במס השולי כקבוע בסעיף 121 לפקודה.

(ג) לפי הפקודה, מי שבהיותו תושב חוץ רכש נכס במטבע חוץ כדין, רשאי לבקש שיראו את שער המטבע כמדד. על אף האמור, בחישוב רווח ההון בידי יחיד הנובע ממכירת ניירות ערך הנקובים במטבע חוץ או שערכם צמוד למטבע חוץ, יראו לצורך חישוב הסכום האינפלציוני את שער המטבע כמדד.

(ד) חבר בני אדם יהיה חייב במס על רווח הון ריאלי ממכירת ניירות ערך בשיעור מס החברות (23% בשנת 2018).

(ה) קרן נאמנות פטורה וכן קופות גמל וגופים הפטורים ממס לפי סעיף 9(2) לפקודה, פטורים ממס בגין רווחי הון ממכירת ניירות ערך כאמור, בהתאם ובכפוף לתנאים הקבועים בפקודה לעניין זה.

(ו) לפי סעיף 92 לפקודה, הפסדי הון בשנת המס, שמקורם במכירה בשנת המס של ניירות ערך הכלולים במסמך הרישום ושאילו היו רווחי הון היו חייבים במס בידי מקבלם, ניתן, ככלל, ובכפוף לסדרי הקדימות בקיזוז הפסדים, לקזז כנגד רווחי הון, לרבות רווחי הון ממכירת ניירות ערך. בשנת המס שבה נוצרו הפסדי ההון ממכירת נייר הערך ניתן לקזזם גם כנגד ריבית ודיבידנד ששולמו בגין אותו נייר ערך או בגין ניירות ערך אחרים בתנאי ששיעור המס החל על ריבית או דיבידנד כאמור לא עולה על שיעור מס החברות ביחס לחברה (23% בשנת 2018) או 25% ביחס ליחיד. בהתאם להוראות סעיף 92(ב) לפקודה ובכפוף לסדרי הקדימות בקיזוז הפסדים, הפסד שלא ניתן לקזזו, כולו או מקצתו, בשנה השוטפת, יקוזז כנגד רווח הון בלבד בשנות המס הבאות בזו אחר זו, לאחר השנה שבה נוצר ההפסד ובלבד שהוגש לפקיד השומה דו"ח לשנת המס בה היה ההפסד.

(ז) לפי סעיף 94ג לפקודה, במכירת מניה על-ידי חבר בני אדם, יופחת מסכום הפסד ההון אשר נוצר ממכירת המניה, סכום דיבידנד שהתקבל בשל המניה במשך 24 החודשים שקדמו למכירה, למעט דיבידנד ששולם עליו מס (למעט מס ששולם מחוץ לישראל) בשיעור של 15% או יותר, אך לא יותר מסכום ההפסד.

(ח) לפי סעיפים 243-164 לפקודה והוראות תקנות מס הכנסה מכוחם (ניכוי מתמורה, מתשלום או מרווח הון במכירת נייר ערך, במכירת יחידה בקרן נאמנות או בעסקה עתידית), התשס"ג - 2002, לעניין ניכוי המס במקור מרווח ההון הריאלי במכירת ניירות הערך המוצעים, חייב (כהגדרת מונח זה בתקנות האמורות) המשלם למוכר תמורה במכירת ניירות הערך, ינכה באמצעות חבר הבורסה מס בשיעור של25% מרווח

ההון הריאלי כאשר המוכר הינו יחיד, ובשיעור מס חברות (23% בשנת 2018) מרווח ההון הריאלי כאשר המוכר הינו חבר בני אדם. האמור לעיל כפוף לאישורי פטור (או שיעור מופחת) מניכוי מס במקור וכפוף לקיזוז הפסדים שרשאי המנכה במקור לבצע. כמו כן, לא ינוכה מס במקור לקופות גמל, קרנות נאמנות וגופים נוספים הפטורים מניכוי מס במקור לפי הדין.

(ט) אם במועד המכירה לא נוכה מלוא המס במקור מרווח ההון הריאלי, יחולו הוראות סעיף 91(ד) לפקודה וההוראות מכוחו בדבר דיווח ותשלום מקדמה על-ידי המוכר בגין מכירה כאמור.

(י) ככלל, תושב חוץ (יחיד או חברה), כמשמעותו בפקודה, פטור ממס על רווחי הון במכירת ניירות ערך הנסחרים בבורסה שנרכשו לאחר מועד הנפקתם אם רווח ההון אינו במפעל הקבע שלו בישראל. כמו כן, לא ינוכה מס במקור על-ידי תאגיד בנקאי או חבר בורסה לתושב חוץ בהתקיים תנאים מסוימים ולאחר המצאת אישורים מתאימים על ידי תושב החוץ.

5.1.1.2. <u>שיעור המס שיחול על הכנסות מדיבידנד בגין מניות החברה</u>

(א) דיבידנד שמקורו במניות החברה, יהיה חייב ככלל במס בידי יחידים תושבי ישראל - בשיעור של 25%, למעט לגבי יחיד שהינו בעל מניות מהותי בחברה במועד קבלת הדיבידנד או במועד כלשהו ב-12 החודשים שקדמו לו, אשר שיעור המס לגביו יהיה 30%.

(ב) מכיוון שהחברה הינה חברה תושבת בריטניה, הרי שככלל, שיעור המס על דיבידנד בידי חברות תושבות ישראל יהיה בשיעור מס החברות (23% בשנת 2018); קרן נאמנות פטורה וכן קופות גמל וגופים אחרים הפטורים ממס בהתאם לסעיף 9(2) לפקודה, יהיו פטורים ממס בגין דיבידנד כאמור, בהתאם לתנאים הקבועים בדין, לרבות שההכנסות כאמור אינן מהוות בידיהן הכנסה מ"עסק".

(ג) על פי תקנות מס הכנסה (ניכוי מריבית, מדיבידנד ומרווחים מסוימים), התשס"ו-2005 (להלן: "**תקנות הניכוי**"), ניכוי המס במקור בחלוקת הדיבידנד ליחיד תושב ישראל בגין מניות החברה יהיה בשיעור 25% ולחברה תושבת ישראל בשיעור מס חברות (23% ב-2018), או כפי שייקבע לפי כל דין במועד חלוקת הדיבידנד. על פי תקנות הניכוי, מקום ששולם דיבידנד למי שלגביו נקבע שיעור מס מוגבל לפי כל דין, ינוכה המס במקור לפי השיעור שנקבע.

(ד) לא ינוכה מס במקור בגין תשלומים לקופות גמל, קרנות נאמנות וגופים נוספים, הפטורים מניכוי מס במקור לפי הדין.

יש לציין כי בשל השינויים המהותיים שחלו במיסוי שוק ההון ובפרק שני 1 לפקודה, בשנים האחרונות, טרם התגבשה הפרקטיקה הנאותה ליישום ההוראות לעיל, ואף ייתכנו מספר פרשנויות לגבי אופן יישומן. יתרה מזאת, ייתכנו שינויים נוספים מעבר לשינויים שבוצעו עד כה בהוראות. יצוין כי תשלום תמורה ודיבידנד לגבי ניירות הערך הנסחרים בישראל נעשה באמצעות חברי הבורסה בישראל ועל תשלומים אלה עשויות לחול הוראות נוספות מעבר למה שכבר פורט לעיל. מטבע הדברים, לא ניתן לצפות את תוכנם והשפעתם של השינויים האמורים.

כמקובל בעת קבלת החלטות על השקעות כספים, יש לשקול את השלכות המס הקשורות בהשקעה בניירות הערך המוצעים. האמור לעיל אינו מתיימר להיות פרשנות מוסמכת של הוראות החוק הנזכרות לעיל או תיאור ממצה של הוראות המס הנוגעות למיסוי ניירות ערך, ואינו בא במקום יעוץ מקצועי בנדון בהתאם לנתונים המיוחדים ולנסיבות הייחודיות לכל משקיע. מוצע כי רוכשי ניירות הערך הכלולים במסמך רישום זה יפנו לקבלת יעוץ מקצועי בהתאם

לנתונים המיוחדים הנוגעים לכל רוכש נייר ערך.

5.2. **<u>מיסוי בריטי (למי שאינם תושבי בריטניה לצורך מס)</u>**

מטרת האמור להלן הינה לתת מידע כללי ביחס למשמעויות מס בריטי מסוימות ואינו מתיימר להוות סקירה ממצה של כל משמעויות המס האפשריות בבריטניה ביחס לרכישה, החזקה ומכירה של מניות הכלולות במסמך רישום זה.

האמור בפרק זה מתבסס על החוק הבריטי במועד מסמך רישום זה ומה שמוכר לנו כפרקטיקה הנוהגת על ידי רשות המס הבריטית (HMRC) אשר שתיהן עלולות להשתנות, לרבות עם תחולה רטרואקטיבית.

האמור בפרק זה מתייחס אך ורק למי שאינם תושבי בריטניה לצרכי מס (ביחס למי שהינם תושבי בריטניה לצרכי מס – ר' עמודים 292-289 לתשקיף המצורף לחלק השני של מסמך רישום זה) ואשר הינם מחזיקים במניות כהשקעה (למעט חשבון השקעה אישי או הסדר השקעה פנסיוני אישי ואשר הינם בעלי הזכות שביושר של מניות והדיבידנדים המשולמים בגינן, ככל וישולמו. האמור להלן אינו כולל התייחסות להסדר המס החל על בעלי מניות הכפופים להסדרים ספציפיים (כגון מי שרוכשים את המניות בקשר עם עבודה, סוחרים בניירות ערך, חברות ביטוח, וקרנות השקעות משותפות).

מטרת הסקירה הינה לתת מידע כללי בלבד ומומלץ מאוד למשקיעים לפנות ליועצי המס האישיים שלהם על מנת לוודא את משמעויות המס החלות עליהם ביחס לרכישה, החזקה ומכירה של ניירות הערך הכלולים במסמך רישום זה.

5.2.1. <u>מיסוי על דיבידנדים</u>

5.2.1.1. החברה אינה נדרשת לנכות מס במקור מדיבידנדים המשולמים על ידה או ריבית המשולמת על דיבידנד. חבות המס של מקבל הדיבידנדים תיקבע לפי הנסיבות האינדיבידואליות של המקבל. בעלי מניות שאינם תושבי בריטניה אינם כפופים למס בריטי על הדיבידנדים המתקבלים (אך עלולים לחוב במס במדינת תושבותם).

5.2.2. <u>מיסוי על מימוש המניות</u>

5.2.2.1. בעלי מניות שאינם תושבי בריטניה לצרכי מס לא יהיו כפופים, ככלל, לחבות מס בבריטניה בגין רווחי הון הנובעים כתוצאה ממימוש או מימוש רעיוני של מניות אלא אם כן הם מנהלים מסחר, מקצוע או משלח יד באנגליה באמצעות סניף או סוכנות (או במקרה של בעל מניות שהינו תאגיד, מוסד קבע) אשר בקשר אליו נעשה השימוש במניות, החזקתן או רכישתן. בעלי מניות שאינם תושבי בריטניה לצרכי מס, עשויים להיות כפופים לחבות מס שאינה בריטית על כל רווח, בכפוף לדין הפנימי החל במדינת תושבתם. בעל מניות יחיד אשר רוכש מניות בעודו תושב בריטניה לצרכי מס, ולאחר מכן באופן זמני הופך למי שאינו תושב בריטניה ומוכר את מניותיו או חלק מהן במהלך התקופה שבה הוא זמנית אינו תושב, עשוי בנסיבות מסוימות, לחוב במס רווחי הון בחזרתו לבריטניה, בכפוף לכל פטור או הקלה.

5.2.3. <u>מס בולים – ("SDRT") **Stamp Duty and Stamp Duty Reserve Tax**</u>

5.2.3.1. הוראות מיוחדות חלות כאשר מניות מונפקות או מועברות לאדם, או לנאמן או לשליח המחזיק מטעמו, שעסקיו הינם או כוללים שירותי סליקה, לפי סעיף 70 או סעיף 96 ל- Finance Act 1986, אשר לפיהם עשוי לקום חיוב ב- Stamp Duty and Stamp Duty Reserve Tax ("**מס בולים**") בשיעור של 1.5% ממחירן בעת ההנפקה, מהסכום או השווי של התמורה כאשר הועברה בתמורה, או משוויין בכל מקרה אחר.

5.2.3.2. בעקבות התדיינות משפטית, רשות המס הבריטית (HMRC) אישרה שהיא לא תפעל להחיל את שיעור המס בגובה 1.5% על הנפקת מניות באמצעות שירותי סליקה, מאחר ואין זה

תואם את החוק של האיחוד האירופאי (EU law). עם זאת, אישור זה לא בא לידי ביטוי בשינוי החוקים הבריטיים. עמדת רשות המס הבריטית היא שמס הבולים בשיעור 1.5% ימשיך לחול על העברת מניות לשירותי סליקה, אלא אם כן הם מהווים חלק אינטגרלי מהנפקת הון המניות. לפיכך, על בעלי המניות לפנות לייעוץ מקצועי בטרם יישאו במס בולים בשיעור של 1.5% בנסיבות האלה.

5.2.3.3. ככלל, למעט ביחס למסלקות שביצעו בחירה על פי סעיף 97A(1) ל- Finance Act 1986 (שלגביו חלים כללים ספציפיים), לא ישולם כל מס בולים בשל העברות בתוך המסלקה. יצוין כי יש חריג לחובת התשלום של מס הבולים בגובה של 1.5% על העברה למסלקה (או סוכן או נאמן עבורה) מקום שהמסלקה ביצעה בחירה לפי סעיף 97A(1) המוזכר לעיל (והמשיכה לעמוד בתנאים הנדרשים הקבועים בו), אשר אושרה על ידי ה- HMRC. בנסיבות אלו, מס בולים בגובה של 0.5% מהסכום או הערך של התמורה ששולמה בגין העברת המניה, ייגבה בגין כל העברת מניות של החברה לתוך המסלקה כאמור וכן על הסכמים עוקבים להעביר מניות אלו בתוך המסלקה. יובהר כי המונח "מסלקה" בסעיף זה אינו כולל את מסלקת הבורסה.

5.2.3.4. **בהתאם לתנאי רישום המניות למסחר בבורסה בתל אביב, לא תבוצע בחירה לפי סעיף 97A(1) היות ולא יהיה אפשרי מבחינה מעשית לבורסה ולבנק יורוקליר (אליו יועברו המניות מהבורסה בלונדון) לנכות את מס הבולים בגין כל העברה של מניות בחשבון מסלקת הבורסה בבנק היורוקליר. כתוצאה מכך, מס בולים בגובה 1.5% עלול לחול על העברת המניות לחשבון מסלקת הבורסה בבנק היורוקליר, והרוכש של מניות אלו הוא שיישא בכך, אולם לא תהיה חובת תשלום מס בולים על העברות של אותן המניות בתוך חשבון מסלקת הבורסה בבנק היורוקליר במסגרת המסחר בבורסה וכן בעת העברה של אותן מניות מחשבון מסלקת הבורסה ביורוקליר לחשבון חבר אחר בבנק היורוקליק. יצוין כי לא יהיה תשלום של מס בולים בעת העברת המניות חזרה ל-CREST**.

6. **<u>השוואה בין הדין האנגלי והדין הישראלי</u>**

טבלת השוואת דינים בין חוק החברות הישראלי וחוק החברות האנגלי מצורפת למסמך רישום זה כ**<u>נספח א'</u>**.

***

נספח א'

השוואת דינים

בין הדין האנגלי לדין הישראלי

COMPARATIVE SHAREHOLDER RIGHTS UNDER ENGLISH LAW AND ISRAELI LAW

The following is a summary comparison of material differences between the rights of a shareholder under Israeli law and under English Law as rising from the differences between the laws of England and Wales and those of the State of Israel.

The following summary does not purport to be a complete statement of the rights of shareholders of Energean Oil & Gas PLC ("**Energean**") under the applicable laws of England and Wales (including the Companies Act 2006 ("**CA06**") and the Listing Rules applicable to companies with a premium listing on the London Stock Exchange), Energean's articles of association or a complete description of the specific provisions referred to in this summary. This summary contains a list of certain of the material differences but is not meant to be relied upon as an exhaustive list or a detailed description of the provisions discussed and is qualified in its entirety by reference to the laws of England and Wales and the laws of the State of Israel.

Summary of Material Differences between the Rights of Shareholder Right under English Law and Shareholder Right under Israeli Law.

	Shareholder Rights Under English Law	**Shareholder Rights Under Israeli Law**
Number of Directors	Public limited companies must have a minimum of two directors and at least one secretary. The board of a listed company and its committees should have the appropriate balance of skills, experience, independence and knowledge of the company to enable them to discharge their respective duties and responsibilities effectively (UK Corporate Governance Code ("**Code**") Main Principle B.1). The board should be of sufficient size that the requirements of the business can be met and that changes to the board's composition and that of its committees can be managed without undue disruption, and should not be so large as to be unwieldy (Code Supporting Principle B.1).	Subject to certain exceptions, a public company must have at least two external directors. In addition, the board of directors must determine the minimum number of directors having financial and accounting expertise.
Election of Directors	Subject to the company's articles of association, any person who is willing to act as a director, and is permitted by law to do so, may be appointed to be a director: (a) by ordinary resolution of the shareholders; (b) at a general meeting (upon board recommendation); (c) by a decision of the board. At every annual general meeting all the directors appointed by the board at the date of the notice convening the annual general meeting shall retire from office.	Unless provided otherwise by the company's articles of association, directors of a public company are elected by the general meeting of the shareholders.
Removal of Directors	The shareholders of the Company may, by ordinary resolution, remove any director from office. A person ceases to be a director under the articles in certain other circumstances, including (a) non-attendance at board meetings for more than six months, (b) if disqualified by law, (c) if a bankruptcy	Unless provided otherwise by the company's articles of association, the general meeting of the shareholders may, at any time, remove a director (other than external directors, which the removal from office requires the same majority that was required to elect them to office) from office, provided that such director was given a reasonable opportunity to express his position before the general meeting.

	order is made against that person, (d) if a composition or arrangement is made with that person's creditors generally in satisfaction of that person's debts, (e) if they become physically or mentally incapable of acting as a director, (f) that person receives notice signed by not less than three quarters of the other directors stating that that person should cease to be a director.	
Board Quorum and Vote Requirements	The quorum for the transaction of the business of the board may be fixed by the board and unless so fixed at any other number shall be two. A person who holds office only as an alternate director may, if his appointor is not present, be counted in the quorum. Questions arising at a meeting shall be decided by a majority of votes. In the case of an equality of votes, the chairman shall not have a second or casting vote.	The quorum for commencing a meeting of the board of directors shall be the majority of the directors, unless provided otherwise in the company's articles of association. Resolutions of the board of directors are passed by ordinary majority; where the votes are even, the chairman of the board of directors shall have a casting vote, unless otherwise provided in the articles of association.
Action of the Board of Directors Without a Meeting	A resolution in writing agreed to by all the directors entitled to vote at a meeting of the board or of a committee of the board (not being less than the number of directors required to form a quorum of the board) shall be as valid and effectual as if it had been passed at a meeting of the board or (as the case may be) a committee of the board duly convened and held.	Unless provided otherwise in the company's articles of association, the board of directors may pass resolutions in writing in lieu of a meeting provided that all of the directors entitled to participate in the discussion and to vote on the matter have agreed to adopt such resolution in writing. If resolutions of the board of directors are passed in writing in lieu of a meeting, minutes of the resolutions that have passed, including the resolution to adopt them in lieu of meeting shall be prepared and executed by the chairman of the board of directors.
Approval of Certain Transactions and Matters	There should be a formal schedule of matters specifically reserved for decision by the board (Code Provision A.1.1). The CA06 sets out the situations in which a company will be required to pass an ordinary (simple majority) or special resolution (majority of not less than 75%) of the shareholders attending and voting at the meeting. These include (but are not limited to the following): <u>Ordinary Resolutions</u>: • to appoint two or more persons as directors of a public company at a single meeting; • to remove a director before the expiration of his term (special notice is required); • to approve directors' long term service contracts (more than two years); • to approve substantial property transactions; • to approve loans to directors; and • to appoint/remove auditors of public company.	Unless provided otherwise in the Companies Law or in the company's articles of association, all shareholders' resolutions shall be approved by a simple majority vote. the following resolutions, among others, will require the approval of the general meeting of the shareholders: • amendment to the articles of association; • appointment of independent auditor; • appointment of external directors; • approval of certain related party transactions and compensation arrangements; • increase and decrease of the registered share capital; and • acts of office holders that require shareholder approval. The term "office holder" is defined under the Companies Law as a general manager, chief business manager, deputy general manager, vice general manager, or any other person assuming the responsibilities of any of the foregoing

	Special Resolutions: • to amend the articles of association of a company; • to change the name of a company; • to re-register a private company (whether limited or unlimited) with a share capital as a public company; and • to grant directors a general authority to withdraw or modify the statutory pre-emption rights which exist on issue of shares by a company.	positions, without regard to such person's title, and a director or manager directly subordinate to the general manager.
Shareholder Meetings	A public company must hold an annual general meeting within the period of six months beginning with the day following its accounting reference date The board of directors has the power to call general meetings. Shareholders representing at least 5% of such of the paid-up capital of the company as carries the right of voting at general meetings of the company, may request that the directors call a general meeting.	A company must convene an annual general meeting of shareholders once in every calendar year and no later than 15 months following the date of the previous annual general meeting. All meetings other than the annual general meeting of shareholders are referred to as special general meetings. In addition, the board of directors requires to convene a special meeting upon the written request of (i) any two directors or one quarter of the directors then in office (ii) one or more shareholders holding, in the aggregate, 5% of the issued share capital and 1% of outstanding voting power or 5% of outstanding voting power of the company.
Quorum Requirements	The necessary quorum shall be two persons entitled to vote upon the business to be transacted, each being a member or a proxy for a member or a duly authorised representative of a corporation which is a member.	The quorum required for a general meeting of shareholders consists of at least two shareholders present in person, by proxy or written ballot who hold or represent between them at least 25% of the total outstanding voting rights, within half an hour from the appointed time.
Action of Shareholders by Written Consent	The CA06 does not allow public companies to adopt shareholder resolutions by means of written resolution in lieu of a holding a general meeting.	The Companies Law does not allow public companies to adopt shareholder resolutions by means of written consent in lieu of a shareholder meeting.
Amendment of Certificate of Incorporation, Bylaws, Articles of Association	An amendment to articles of association of a company requires approval of a majority of not less than 75% of those attending and voting at a general meeting.	An amendment to articles of association of a company requires approval of a simple majority vote of the general meetings of shareholders, unless the company's articles of association provide that a different majority is required.
Exculpation, Insurance and indemnification of Directors, Officers and Employees	The CA06 generally prohibits a company from indemnifying a director against his liability for negligence, default, breach of duty or breach of trust in relation to the company or an associated company (a "**claim**"). A company is permitted to indemnify its directors or directors of its associated companies against liability incurred in connection with a claim by third parties other than the company or any associated company. A company is permitted to indemnify directors of a company which is a trustee of an occupational pension scheme against liability incurred in connection with the company's activities as trustee of the scheme.	Under the Companies Law, a company may not exculpate an office holder from liability for a breach of the duty of loyalty. A company may exculpate an office holder in advance from liability to the company, in whole or in part, for damages caused to the company as a result of a breach of the duty of care but only if a provision authorizing such exculpation is included in its articles of association. An Israeli company may not exculpate a director from liability arising out of a breach of the duty of care with respect to a dividend or distribution to shareholders. Under the Companies Law and the Israeli Securities Law, 5738—1968 (the "**Securities Law**"), a company may indemnify an office holder in respect of the following liabilities, payments and expenses incurred for acts performed as an

	A company is permitted, at its own cost, to purchase and maintain insurance for its directors or the directors of its associated companies. The CA06 specifically allows companies to maintain D&O insurance, which will give directors comfort that they will not be required to fund possibly protracted and expensive litigation from their own personal resources.	office holder, either pursuant to an undertaking made in advance of an event or following an event, provided a provision authorizing such indemnification is contained in its articles: • a monetary liability incurred by or imposed on him or her in favor of another person pursuant to a judgment, including a settlement or arbitrator's award approved by a court. However, if an undertaking to indemnify an office holder with respect to such liability is provided in advance, then such undertaking must be limited to certain events which, in the opinion of the board of directors, can be foreseen based on the company's activities when the undertaking to indemnify is given, and to an amount or according to criteria determined by the board of directors as reasonable under the circumstances, and such undertaking shall detail the foreseen events and described above amount or criteria; • reasonable litigation expenses, including reasonable attorneys' fees, incurred by the office holder as (1) a result of an investigation or proceeding instituted against him or her by an authority authorized to conduct such investigation or proceeding, provided that (i) no indictment was filed against such office holder as a result of such investigation or proceeding; and (ii) no financial liability was imposed upon him or her as a substitute for the criminal proceeding as a result of such investigation or proceeding or, if such financial liability was imposed, it was imposed with respect to an offense that does not require proof of criminal intent; or (2) in connection with a monetary sanction; a monetary liability imposed on him or her in favor of an injured party at an Administrative Procedure (as defined below) pursuant to Section 52(54)(a)(1)(a) of the Securities Law; • expenses incurred by an office holder in connection with an Administrative Procedure under the Securities Law, including reasonable litigation expenses and reasonable attorneys' fees; and • reasonable litigation expenses, including attorneys' fees, incurred by the office holder or imposed by a court in proceedings instituted against him or her by the company, on its behalf or by a third party or in connection with criminal proceedings in which the office holder was acquitted or as a result of a conviction for an offense that does not require proof of criminal intent. "Administrative Procedure" is defined as a procedure pursuant to chapters H3 (Monetary Sanction by the Israeli Securities Authority), H4 (Administrative Enforcement Procedures of the Administrative Enforcement Committee) or I1 (Arrangement to prevent Procedures or Interruption of procedures subject to conditions) to the Securities Law.

		Under the Companies Law and the Securities Law, a company may insure an office holder against the following liabilities incurred for acts performed by him or her as an office holder if and to the extent provided in the company's articles of association: • a breach of duty of care to the company or to a third party, to the extent such a breach arises out of the negligent conduct of the office holder; • a breach of duty of loyalty to the company, provided that the office holder acted in good faith and had a reasonable basis to believe that the act would not harm the company; • a monetary liability imposed on the office holder in favor of a third party; • a monetary liability imposed on the office holder in favor of an injured party at an Administrative Procedure pursuant to Section 52(54)(a)(1)(a) of the Securities Law; and • expenses incurred by an office holder in connection with an Administrative Procedure, including reasonable litigation expenses and reasonable attorneys' fees. Under the Companies Law, a company may not indemnify, exculpate or insure an office holder against any of the following: • a breach of duty of loyalty, except for indemnification and insurance for a breach of the duty of loyalty to the company to the extent that the office holder acted in good faith and had a reasonable basis to believe that the act would not harm the company; • a breach of the duty of care committed intentionally or recklessly, excluding a breach arising out of the negligent conduct of the office holder; • an act or omission committed with intent to derive illegal personal benefit; or • a fine or forfeit levied against the office holder. Under the Companies Law, exculpation, indemnification and insurance of office holders must be approved by the compensation committee and the board of directors and, with respect to certain office holders or under certain circumstances, also by the shareholders.
Fiduciary Duties of Office Holders	English law does not have the concept of "Office Holders" however; the CA06 codified certain common law and equitable duties of directors. In summary, the seven general duties under the CA06 are: • To act within powers; • To promote the success of the company; • To exercise independent judgment;	The Companies Law imposes a duty of care and a duty of loyalty on all office holders of a company. The duty of care of an office holder is based on the duty of care set forth in connection with the tort of negligence under the Israeli Torts Ordinance (New Version), 5728-1968. The duty of care requires an office holder to act with the

	• To exercise reasonable care, skill and diligence; • To avoid conflicts of interest; • Not to accept benefits from third parties; and • To declare an interest in a proposed transaction or arrangement. The codification is not exhaustive. The statutory duties do not cover all the duties that a director may owe to the company, such as: • The duty to consider or act in the interests of creditors, which is expressly preserved by section 172(3) (and stated by the explanatory notes to apply in times of threatened insolvency). • The equitable duty of confidence owed by a director to the company, although it would appear that the duty of confidentiality will now be subordinate to the general duties. The general duties apply to all the directors of a company. "Director" is defined to include any person occupying the position of director, by whatever name called (section 250), which includes de facto directors. The duties are owed to the company. Only the company will be able to enforce them. Directors do not, by virtue of the office of director, owe fiduciary duties to the company's shareholders or creditors, although in certain circumstances shareholders may be able to bring a derivative action on the company's behalf (see Action by the company, below).	degree of proficiency with which a reasonable office holder in the same position would have acted under the same circumstances. The duty of care includes, among others, a duty to use reasonable means, in light of the circumstances, to obtain: • information on the advisability of a given action brought for his or her approval or performed by virtue of his or her position; and • all other important information pertaining to these actions. The duty of loyalty requires an office holder to act in good faith and for the benefit of the company, and includes, among others, the duty to: • refrain from any act involving a conflict of interest between the performance of his or her duties in the company and his or her other duties or personal affairs; • refrain from any activity that is competitive with the business of the company; • refrain from exploiting any business opportunity of the company for the purpose of gaining a personal benefit for himself or herself or for others; and • disclose to the company any information or documents relating to the company's affairs which the office holder received as a result of his or her position as an office holder. A company may approve an act specified above that would otherwise constitute a breach of the duty of loyalty of an office holder, provided, that the office holder acted in good faith, the act or its approval is for the benefit of the company, and the office holder discloses his or her personal interest, including any related material information or document, a sufficient time before the approval of such act. Any such approval is subject to the terms of the Companies Law, setting forth, among other things, the organs of the company entitled to provide such approval, and the methods of obtaining such approval.
Business Combinations; Interested Shareholder Transactions; Anti-Takeover Effects	<u>Related Party Transactions</u> The Listing Rules on Related Party Transactions applies to any a transaction between a listed company and a related party of that company. Related Parties are: • shareholders holding 10% or more of the company's shares; • any person who is or was, in the 12 months before the transaction a director or shadow director of the listed company, any subsidiary undertaking (which is not an insignificant subsidiary), parent undertaking or a fellow subsidiary of its parent undertaking;	Pursuant to the Companies Law, the disclosure requirements regarding personal interests that apply to directors and executive officers also apply to a controlling shareholder of a public company. The approval of the audit committee or the compensation committee, as the case may be, the board of directors and the shareholders of the company, in that order is required for (a) extraordinary transactions with a controlling shareholder or in which a controlling shareholder has a personal interest, (b) the engagement with a controlling shareholder or his or her relative, directly or indirectly, for the provision of services to the company, (c) the terms of engagement and compensation of a controlling shareholder or his or her relative who is not an office holder or (d) the employment of a controlling

	• a person exercising significant influence (that is, a person or entity which exercises significant influence over the listed company); and • an associate of any of the above. The transaction will need to be assessed relative to the size of the listed company. If the transaction represents more than 5% of the company under the relevant class tests, the related party transaction will require (a) notification to a regulatory information service containing prescribed details of the transaction and the related party; (b) an explanatory circular to be sent to shareholders; (c) shareholder approval prior to the transaction being entered into or, if shareholder approval is made a condition, prior to completion. If the transaction represents less than 5% of the company under the relevant class tests, the related party transaction will require (a) notification to a regulatory information service containing prescribed details of the transaction and the related party and (b) confirmation from the company's listing sponsor that the terms of the transaction are fair and reasonable as far as the shareholders are concerned. *Public Takeovers* The City Code on Takeovers and Mergers (the "**Takeover Code**") is a statutory set of rules for the purposes of all takeover offers and other merger transactions which it regulates and the Panel on Mergers and Takeovers (the "**Panel**") has certain statutory powers of enforcement. The Takeover Code is designed to ensure that shareholders are treated fairly, are not denied an opportunity to decide on the merits of a takeover and are afforded equivalent treatment by an offeror. It provides an orderly framework within which takeovers are conducted. The following is a brief summary of some of the most important Rules: When a person or group acquires interests in shares carrying 30% or more of the voting rights of a company, they must make a cash offer to all other shareholders at the highest price paid in the 12 months before the offer was announced (30% of the voting rights of a company is treated by the Takeover Code as the level at which effective control is obtained). When interests in shares carrying 10% or more of the voting rights of a class have been acquired by an offeror (i.e. a bidder) in the offer period and the previous 12 months, the offer must include a cash alternative for all shareholders of that class at the highest price paid by	shareholder or his or her relative by the company, other than as an office holder (collectively referred as Transaction with a Controlling Shareholder). *Merger* The Companies Law permits merger transactions with the approval of each party's board of directors and shareholders. Under the Companies Law, a merging company must inform its creditors of the proposed merger. Any creditor of a party to the merger may seek a court order to delay or block the merger, if there is a reasonable concern that the surviving company will not be able to satisfy all of the obligations of the parties to the merger. Moreover, a merger may not be completed until all of the required approvals have been filed by both merging companies with the Israeli Registrar of Companies and (i) 30 days have passed from the time both companies' shareholders resolved to approve the merger, and (ii) at least 50 days have passed from the time that the merger proposal was filed with the Israeli Registrar of Companies. *Special Tender Offer* The Companies Law provides that an acquisition of shares of a public Israeli company must be made by means of a special tender offer if as a result of the acquisition the purchaser would become a holder of at least 25% of the voting rights in the company. This rule does not apply if there is already another holder of at least 25% of the voting rights in the company. Similarly, the Companies Law provides that an acquisition of shares in a public company must be made by means of a tender offer if as a result of the acquisition the purchaser would become a holder of more than 45% of the voting rights in the company, if there is no other shareholder of the company who holds more than 45% of the voting rights in the company. These requirements do not apply if the acquisition (i) occurs in the context of a private placement, provided that the general meeting approved the acquisition as a private offering whose purpose is to give the acquirer at least 25% of the voting rights in the company if there is no person who holds at least 25% of the voting rights in the company, or as a private offering whose purpose is to give the acquirer 45% of the voting rights in the company, if there is no person who holds 45% of the voting rights in the company, (ii) was from a shareholder holding at least 25% of the voting rights in the company and resulted in the acquirer becoming a holder of at least 25% of the voting rights in the company, or (iii) was from a holder of more than 45% of the voting rights in the company and resulted in the acquirer becoming a holder of more than 45% of the voting rights in the company. *Full Tender Offer*

	the offeror in that period. Further, if an offeror acquires for cash any interest in shares during the offer period, a cash alternative must be made available at that price at least. If the offeror acquires an interest in shares in an offeree company (i.e. a target) at a price higher than the value of the offer, the offer must be increased accordingly. The offeree company must appoint a competent independent adviser whose advice on the financial terms of the offer must be made known to all the shareholders, together with the opinion of the board. Favourable deals for selected shareholders are banned. All shareholders must be given the same information. Those issuing takeover circulars must include statements taking responsibility for the contents. Profit forecasts, quantified financial benefits statements and asset valuations must be made to specified standards and must be reported on by professional advisers. Misleading, inaccurate or unsubstantiated statements made in documents or to the media must be publicly corrected immediately. Actions during the course of an offer by the offeree company which might frustrate the offer are generally prohibited unless shareholders approve these plans. Stringent requirements are laid down for the disclosure of dealings in relevant securities during an offer. Employees of both the offeror and the offeree company and the trustees of the offeree company's pension scheme must be informed about an offer. In addition, the offeree company's employee representatives and pension scheme trustees have the right to have a separate opinion on the effects of the offer on employment appended to the offeree board's circular or published on a website.	A person wishing to acquire shares of a public Israeli company and who would as a result hold over 90% of the target company's issued and outstanding share capital or that of a certain class of shares is required by the Companies Law to make a tender offer to all of the company's shareholders or the shareholders who holds shares of the same class for the purchase of all of the issued and outstanding shares of the company or of the same class, as applicable. If the shareholders who do not respond to or accept the offer hold less than 5% of the issued and outstanding share capital of the company or of the applicable class of the shares, all of the shares that the acquirer offered to purchase will be transferred to the acquirer by operation of law (provided that a majority of the offerees that do not have a personal interest in such tender offer shall have approved it, which condition shall not apply if offerees holding less than 2% of the company's issued and outstanding share capital failed to approve such tender offer). Upon a successful completion of such a full tender offer, any shareholder that was an offeree in such tender offer, whether the shareholder accepted the tender offer or not, may, within six months from the date of acceptance of the tender offer, petition the Israeli court to determine whether the tender offer was for less than fair value and that the fair value should be paid as determined by the court unless the acquirer stipulated that a shareholder that accepts the offer may not seek appraisal rights. If the shareholders who did not respond or accept the tender offer hold at least 5% of the issued and outstanding share capital of the company or of the applicable class, or the shareholders who did not accept the tender offer hold 2% or more of the issued and outstanding share capital of the company (or of the applicable class), the acquirer may not acquire shares of the company that will increase its holdings to more than 90% of the company's issued and outstanding share capital or of the applicable class from shareholders who accepted the tender offer.
Shareholder Duties	There are no explicit shareholder duties under English law however, in the interests of good governance investors should communicate clearly with directors and "police" boardroom practices – i.e. monitor compliance with the Code.	Under the Companies Law, a shareholder has a duty to refrain from abusing its power in the company and to act in good faith and in an acceptable manner in exercising its rights and performing its obligations to the company and other shareholders, including, among other things, when voting at general meetings of shareholders on the following matters: • an amendment to the articles of association; • an increase in the company's authorized share capital; • a merger; and • the approval of related party transactions and acts of office holders that require shareholder approval.

		A shareholder also has a general duty to refrain from discriminating against other shareholders. In addition, any controlling shareholder, any shareholder that knows that its vote can determine the outcome of a shareholder vote and any shareholder that, under a company's articles of association, has the power to appoint or prevent the appointment of an office holder, or any other power with respect to the company, has a duty to act with fairness towards the company. The Companies Law does not describe the substance of this duty, except to state that the remedies generally available upon a breach of contract will also apply in the event of a breach of the duty to act with fairness, taking the shareholder's position in the company into account.
Internal Auditor	Under the CA06, a public company must appoint an auditor for each financial year of the company. Under the CA06 shareholders may appoint auditors of public companies by ordinary resolution at the general meeting of the company at which the company's annual accounts are laid (usually the annual general meeting, also known as the accounts meeting). Members can also appoint auditors if the company should have made the appointment at such an accounts meeting but failed to do so or where the directors have the power but have failed to do so. The auditor must be re-appointed each year, unlike for private companies there is no deemed re-appointment of auditors of public companies.	Under the Companies Law, the board of directors of a public company must appoint an internal auditor based on the recommendation of the audit committee. The role of the internal auditor is, among other things, to examine whether a company's actions comply with applicable law and orderly business procedure. Under the Companies Law, the internal auditor may not be an interested party or an office holder or a relative of an interested party or of an office holder, nor may the internal auditor be the company's independent auditor or the representative of the same. An "interested party" is defined in the Companies Law as (i) a holder of 5% or more of the issued share capital or voting power in a company, (ii) any person or entity who has the right to designate one or more directors or to designate the chief executive officer of the company, or (iii) any person who serves as a director or as a chief executive officer of the company.
Disclosure of personal interest of an office holder and approval of related party transactions	Under the CA06 directors have a duty to declare an interest in a proposed transaction or arrangement. Directors must declare to the other directors the nature and extent of any interest, direct or indirect, in a proposed transaction or arrangement with the company. The director need not be a party to the transaction for the duty to apply. An interest of another person in a contract with the company may require the director to make a disclosure under this duty, if the other person's interest amounts to a direct or indirect interest on the part of the director. The declaration must be made before the company enters into the transaction or arrangement and may be made at a meeting of the directors, or by notice in writing. No declaration will be required (a) where the director is not aware of his or her interest or where the director is not aware of the transaction	The Companies Law requires that an office holder promptly disclose to the company any personal interest that he or she may have and all related material information or documents relating to any existing or proposed transaction by the company. An interested office holder's disclosure must be made promptly and, in any event, no later than the first meeting of the board of directors at which the transaction is considered. An office holder is not obliged to disclose such information if the personal interest of the office holder derives solely from the personal interest of his or her relative in a transaction that is not considered as an extraordinary transaction. Under the Companies Law, once an office holder has complied with the above disclosure requirement, a company may approve a transaction between the company and the office holder or a third party in which the office holder has a personal interest, pursuant to the certain procedures as set forth in the Companies Law. However, a company may not approve a transaction or action that is not to the company's benefit.

	or arrangement, but directors will be treated as being aware of matters of which they ought reasonably to be aware; (b) if the interest cannot reasonably be regarded as likely to give rise to a conflict of interest, if the other directors are already aware of it, or if it concerns the terms of the director's service contract which have been (or are to be) considered at a board meeting or board committee; or (c) where the company has only one director. The board may authorise any matter which would, if not so authorised, involve a breach of duty by a director including, without limitation, any matter which relates to a situation in which a director has, or can have, an interest which conflicts, or possibly may conflict, with the interests of the Company (an "**Interested Director**"). Any such authorisation will be effective only if: • any requirement as to quorum at the meeting at which the matter is considered is met without counting the Interested Director or any other interested director; and • the matter was agreed to without their voting or would have been agreed to if their votes had not been counted. The board may (whether at the time of the giving of the authorisation or subsequently) make any such authorisation subject to any limits or conditions it expressly imposes but such authorisation is otherwise given to the fullest extent permitted by law.	Under the Companies Law, unless the articles of association of a company provide otherwise, a transaction with an office holder or with a third party in which the office holder has a personal interest, which is not an extraordinary transaction, requires the approval by the board of directors. If the transaction considered is an extraordinary transaction with an office holder or a third party in which the office holder has a personal interest, then audit committee approval is required prior to approval by the board of directors. Any person who has a personal interest in the approval of a transaction that is brought before a meeting of the board of directors or the audit committee may not be present at the meeting or vote on the matter. However, if the chairman of the board of directors or the chairman of the audit committee, as applicable, has determined that the presence of an office holder with a personal interest is required, such office holder may be present at the meeting for the purpose of presenting the matter. Notwithstanding the foregoing, a director who has a personal interest may be present at the meeting of the audit committee or the board of directors and vote on the matter if a majority of the directors or members of the audit committee, as applicable, have a personal interest in the approval of such transaction. If a majority of the directors at a board of directors meeting have a personal interest in the transaction, such transaction also requires approval of the shareholders of the company. A "personal interest" is defined under the Companies Law as the personal interest of a person in an action or in a transaction of the company, including the personal interest of such person's relative or the interest of any other corporate body in which the person and/or such person's relative is a director or general manager, a holder of 5% or more of the issued and outstanding share capital of the company or its voting rights, or has the right to appoint at least one director or the general manager, but excluding a personal interest stemming solely from the fact of holding shares in the company. A personal interest also includes (1) a personal interest of a person who votes according to a proxy of another person, including in the event that the other person has no personal interest, and (2) a personal interest of a person who gave a proxy to another person to vote on his or her behalf regardless of whether the discretion of how to vote lies with the person voting or not. An "extraordinary transaction" is defined under the Companies Law as any of the following: • a transaction other than in the ordinary course of business; • a transaction that is not on market terms; or • a transaction that may have a material impact on the company's profitability, assets or liabilities.

Compensation of office holders	For a public company the remuneration committee will recommend the policy and framework on executive remuneration, determine the levels of remuneration for Executive Directors, the Chairman and other senior executives and prepare an annual remuneration report for approval by the shareholders at the annual general meeting. The remuneration committee will also review the scale and structure of Executive Directors' remuneration and the terms of their service or employment contracts, including share-based schemes, other employee incentive schemes adopted by the Company from time to time and pension contributions and ensure that payments made on termination are fair to the individual and the Company. The remuneration committee should meet at such times as are necessary, but not less than twice a year.	The compensation of, or an undertaking to indemnify or insure, an office holder requires approval first by the company's compensation committee, then by the company's board of directors, and, if such compensation arrangement or an undertaking to indemnify or insure is that of a director, the approval of the shareholders by an ordinary majority. If such compensation arrangement or an undertaking to indemnify or insure is inconsistent with the company's stated compensation policy, or in the case of the compensation arrangement of the chief executive officer, then such arrangement is subject to the approval of a majority vote of the shares present and voting at a shareholders meeting, provided that either: (a) such majority includes at least a majority of the shares held by all shareholders who do not have a personal interest in such compensation arrangement and are not controlling shareholders, excluding abstentions; or (b) the total number of shares of shareholders who do not have a personal interest in the compensation arrangement and who vote against the arrangement does not exceed 2% of the company's aggregate voting rights.

נספח 1

תשקיף החברה מיום 16 במרץ 2018

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IMPORTANT: You must read the following disclaimer before continuing. This electronic transmission applies to the attached document and you are therefore advised to read this disclaimer carefully before reading, accessing or making any other use of the attached prospectus (the "**Prospectus**") relating to Energean Oil & Gas plc (the "**Company**") dated 16 March 2018 accessed from this page or otherwise received as a result of such access. In accessing the attached document, you agree to be bound by the following terms and conditions, including any modifications to them from time to time, each time you receive any information from us as a result of such access. You acknowledge that this electronic transmission and the delivery of the attached document is confidential and intended for you only and you agree you will not forward, reproduce, copy, download or publish this electronic transmission or the attached document whether electronically or otherwise to any other person. The Prospectus has been prepared solely in connection with the proposed offer to certain institutional and professional investors (the "**Global Offer**") of ordinary shares (the "**Shares**") of the Company. The Prospectus has been published in connection with the admission of the Shares to the premium listing segment of the Official List of the UK Financial Conduct Authority (the "**FCA**") and to trading on the London Stock Exchange plc's main market for listed securities (together, "**Admission**"). The Prospectus has been approved by the FCA as a prospectus prepared in accordance with the Prospectus Rules made under section 73A of the FSMA. The Prospectus has been published and is available from the Company's registered office and on the Company's website at http://www.energean.com/investors. Pricing information and other related disclosures have also been published on this website. Prospective investors are advised to access such information prior to making any investment decision and should not purchase or subscribe for the Shares except on the basis of the Prospectus.

THIS ELECTRONIC TRANSMISSION AND THE ATTACHED DOCUMENT MAY ONLY BE DISTRIBUTED IN CONNECTION WITH "**OFFSHORE TRANSACTIONS**" AS DEFINED IN, AND IN RELIANCE ON, REGULATION S UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") ("**REGULATION S**") OR WITHIN THE UNITED STATES TO QUALIFIED INSTITUTIONAL BUYERS ("**QIBs**") AS DEFINED IN RULE 144A UNDER THE U.S. SECURITIES ACT ("**RULE 144A**") OR PURSUANT TO ANOTHER EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE U.S. SECURITIES ACT. ANY FORWARDING, DISTRIBUTION OR REPRODUCTION OF THE ATTACHED DOCUMENT IN WHOLE OR IN PART IS UNAUTHORISED. FAILURE TO COMPLY WITH THIS NOTICE MAY RESULT IN A VIOLATION OF THE U.S. SECURITIES ACT OR THE APPLICABLE LAWS OF OTHER JURISDICTIONS. NOTHING IN THIS ELECTRONIC TRANSMISSION AND THE ATTACHED DOCUMENT CONSTITUTES AN OFFER OF SECURITIES FOR SALE IN ANY JURISDICTION WHERE IT IS UNLAWFUL TO DO SO.

THE SHARES REFFERED TO HEREIN HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE U.S. SECURITIES ACT OR WITH ANY SECURITIES REGULATORY AUTHORITY OF ANY STATE OF THE UNITED STATES OR OTHER JURISDICTION AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) TO A PERSON THAT THE SELLER AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVES IS A QIB IN RELIANCE ON RULE 144A OR PURSUANT TO ANOTHER EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE U.S. SECURITIES ACT OR (2) IN AN "**OFFSHORE TRANSACTION**" AS DEFINED IN, AND IN ACCORDANCE WITH RULE 903 OR RULE 904 OF, REGULATION S, IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES.

This electronic transmission and the attached document and the Global Offer when made are only addressed to and directed at persons in member states of the European Economic Area who are "qualified investors" within the meaning of Article 2(1)(e) of the Prospectus Directive (Directive 2003/71/EC) and amendments thereto ("**Qualified Investors**"). In addition, in the United Kingdom, this electronic transmission and the attached document is being distributed only to, and is directed only at, Qualified Investors (i) who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "**Order**") and Qualified Investors falling within Article 49(2)(a) to (d) of the Order, and (ii) to whom it may otherwise lawfully be communicated (all such persons together being referred to as "**relevant persons**"). This electronic transmission and the attached document must not be acted on or relied on (i) in the United Kingdom, by persons who are not relevant persons, and (ii) in any member state of the European Economic Area other than the United Kingdom, by persons who are not Qualified Investors. Any investment or investment activity to which this document relates is available only to (i) in the United Kingdom, relevant persons, and (ii) in any member state of the European Economic Area other than the United Kingdom, Qualified Investors, and will be engaged in only with such persons.

The attached document does not constitute a prospectus under the Israeli Securities Law, 5728-1968, and has not been filed with or approved by the Israel Securities Authority. In Israel, this Prospectus is being distributed only to, and is directed only at, investors listed in the first addendum, to the Israeli Securities Law (the "**Addendum**"), consisting primarily of joint investment in trust funds; provident funds; insurance companies; banks; portfolio managers, investment advisors, members of the Tel Aviv Stock Exchange Ltd., underwriters, each purchasing for their own account; venture capital funds; entities with equity in excess of NIS 50 million and "qualified individuals," each as defined in the Addendum (as it may be amended from time to time), collectively referred to as "Qualified Israeli Investors". Qualified Israeli Investors shall be required to submit written confirmation that they fall within the scope of the Addendum.

Information to Distributors

Solely for the purposes of the product governance requirements contained within: (a) EU Directive 2014/65/EU on markets in financial instruments, as amended ("**MiFID II**"); (b) Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II; and (c) local implementing measures (together, the "**MiFID II Product Governance Requirements**"), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the Product Governance Requirements) may otherwise have with respect thereto, the Shares have been subject to a product approval process, which has determined that such Shares are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients and eligible counterparties, each as defined in MiFID II; and (ii) eligible for distribution through all distribution channels as are permitted by MiFID II (the "**Target Market Assessment**"). Notwithstanding the Target Market Assessment, Distributors should note that: the price of the Shares may decline and investors could lose all or part of their investment; the Shares offer no guaranteed income and no capital protection; and an investment in the Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Offer. Furthermore, it is noted that, notwithstanding the Target Market Assessment, the Joint Bookrunners will only procure investors who meet the criteria of professional clients and eligible counterparties.

For the avoidance of doubt, the Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Shares.

Each distributor is responsible for undertaking its own target market assessment in respect of the Shares and determining appropriate distribution channels.

Confirmation of your Representation: This electronic transmission and the attached document is delivered to you on the basis that you are deemed to have represented to Citigroup Global Markets Limited, Morgan Stanley & Co. International plc, RBC Europe Limited, Stifel Nicolaus Europe Limited (together, the "**Underwriters**"), Natixis, Poalim IBI Underwriting & Issuing LTD and Société Générale (together with the Underwriters, the "**Managers**"), N. M. Rothschild & Sons Limited ("**Rothschild**" or the "**Financial Adviser**"), the Company and the Major Shareholders (as defined in Part 17 "*Definitions*") that (i) if you are in the United

States you are a QIB acting for your own account or for the account of another QIB; (ii) if you are in the United Kingdom, you are a relevant person, and/or a relevant person who is acting on behalf of, relevant persons in the United Kingdom and/or Qualified Investors to the extent you are acting on behalf of persons or entities in the United Kingdom or the European Economic Ares ("**EEA**"); (iii) if you are in any member state of the European Economic Area other than the United Kingdom, you are a Qualified Investor and/or a Qualified Investor acting on behalf of, Qualified Investors or relevant persons, to the extent you are acting on behalf of persons or entities in the EEA or the United Kingdom; and (iv) you are an institutional investor that is eligible to receive this document and you consent to delivery by electronic transmission.

The Managers and the Financial Adviser are acting exclusively for the Company and no one else in connection with the Global Offer. They will not regard any other person (whether or not a recipient of this document) as their client in relation to the Global Offer and will not be responsible to anyone other than the Company for providing the protections afforded to their respective clients nor for giving advice in relation to the Global Offer or any transaction or arrangement referred to in the attached document.

You are reminded that you have received this electronic transmission and the attached document on the basis that you are a person into whose possession this document may be lawfully delivered in accordance with the laws of the jurisdiction in which you are located and you may not nor are you authorised to deliver this document, electronically or otherwise, to any other person. This document has been made available to you in an electronic form. You are reminded that documents transmitted via this medium may be altered or changed during the process of electronic transmission and consequently none of the Company, the Major Shareholders, the Managers, the Financial Adviser nor any of their respective affiliates accepts any liability or responsibility whatsoever in respect of any difference between the document distributed to you in electronic format and the hard copy version. By accessing the attached document, you consent to receiving it in electronic form. None of the Managers, the Financial Adviser nor any of their respective affiliates accepts any responsibility whatsoever for the contents of the attached document or for any statement made or purported to be made by it, or on its behalf, in connection with the Company, the Global Offer or the Shares. To the fullest extent permitted by law, the Managers, the Financial Adviser and each of their respective affiliates, each accordingly disclaims all and any liability whether arising in tort, contract or otherwise which they might otherwise have in respect of such document or any such statement. No representation or warranty express or implied, is made by any of the Managers, the Financial Adviser or any of their respective affiliates as to the accuracy, completeness, reasonableness, verification or sufficiency of the information set out in the attached document.

Restriction: Nothing in this electronic transmission constitutes, and this electronic transmission may not be used in connection with, an offer of securities for sale to persons other than the specified categories of institutional buyers described above and to whom it is directed and access has been limited to that it shall not constitute a general solicitation. If you have gained access to this transmission contrary to the foregoing restrictions, you will be unable to purchase any of the securities described herein.

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ENERGEAN
OIL & GAS



Energean Oil & Gas plc

Prospectus

16 March 2018

This document comprises a prospectus (the "**Prospectus**") for the purposes of Article 3 of European Union Directive 2003/71/EC, as amended (the "**Prospectus Directive**") relating to Energean Oil & Gas plc (the "**Company**") prepared in accordance with the Prospectus Rules of the Financial Conduct Authority (the "**FCA**") made under section 73A of the Financial Services and Markets Act 2000 (the "**FSMA**"). The Prospectus will be made available to the public in accordance with the Prospectus Rules.

Application has been made to the FCA for all of the ordinary shares of the Company (the "**Shares**") issued and to be issued in connection with the Global Offer to be admitted to the premium listing segment of the Official List of the FCA and to London Stock Exchange plc (the "**London Stock Exchange**") for all of the Shares to be admitted to trading on the London Stock Exchange's main market for listed securities (together, "**Admission**"). Conditional dealings in the Shares are expected to commence on the London Stock Exchange on 16 March 2018. It is expected that Admission will become effective and that unconditional dealings in the Shares will commence on 21 March 2018. **All dealings before the commencement of unconditional dealings will be of no effect if Admission does not take place and such dealings will be at the sole risk of the parties concerned. No application is currently intended to be made for the Shares to be admitted to listing or dealt with on any other exchange.**

The directors of the Company, whose names appear on page 123 of this Prospectus (the "**Directors**"), and the Company accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Directors and the Company (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this Prospectus is in accordance with the facts and contains no omission likely to affect the import of such information.

Prospective investors should carefully read this Prospectus in its entirety. In particular, see Part 1 "*Risk Factors*" for a discussion of certain risks and other factors that should be considered prior to any investment in the Shares.

Energean Oil & Gas plc

(Incorporated under the Companies Act 2006 and registered in England and Wales with registered number 10758801)

Global Offer of 72,592,016 Shares at an Offer Price of 455 pence per Share and admission to the Premium Listing Segment of the Official List and to trading on the Main Market of the London Stock Exchange

Joint Global Co-ordinators and Joint Bookrunners

Citigroup **Morgan Stanley** **Stifel**

Joint Sponsors

Citigroup **Morgan Stanley**

Joint Bookrunner

RBC Capital Markets

Co-lead Managers

Natixis **Poalim IBI**

Société Générale Corporate & Investment Banking

Financial Adviser

Rothschild

ORDINARY SHARE CAPITAL IMMEDIATELY FOLLOWING ADMISSION

Issued and fully paid	
Number	**Nominal Value**
152,823,238	£0.01 per share

Each of Citigroup Global Markets Limited, Morgan Stanley & Co. International plc and RBC Europe Limited is authorised by the Prudential Regulation Authority (the "**PRA**") and regulated by the FCA and the PRA in the United Kingdom. N M Rothschild & Sons Limited and Stifel Nicolaus Europe Limited are authorised and regulated by the FCA in the United Kingdom. Natixis and Société Générale are authorised and supervised by the European Central Bank ("**ECB**") and the Autorité de Contrôle Prudentiel et de Résolution (the French Prudential Control and Resolution Authority) ("**ACPR**") and regulated by the Autorité des Marchés Financiers (the French financial markets regulator) ("**AMF**"). Citigroup Global Markets Limited, Morgan Stanley & Co. International plc, RBC Europe Limited, Stifel Nicolaus Europe Limited (together, the "**Underwriters**"), Natixis, Poalim IBI Underwriting & Issuing LTD and Société Générale (together with the Underwriters, the "**Managers**") and N. M. Rothschild & Sons Limited ("**Rothschild**" or the "**Financial Adviser**" and, together with the Managers, the "**Banks**") are acting exclusively for the Company and no-one else in connection with the Global Offer. None of the Banks will regard any other person (whether or not a recipient of this Prospectus) as a client in relation to the Global Offer and will not be responsible to anyone other than the Company for providing the protections afforded to their respective clients or for the giving of advice in relation to the Global Offer or any transaction, matter, or arrangement referred to in this Prospectus. Apart from the responsibilities and liabilities, if any, which may be imposed on the Banks by the FSMA or the regulatory regime established thereunder or under the regulatory regime of any jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, none of the Banks nor any of their respective affiliates accepts any responsibility whatsoever for the contents of this Prospectus including its accuracy, completeness and verification or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the Shares or the Global Offer. Each of the Banks and each of their respective affiliates accordingly disclaim, to the fullest extent permitted by applicable law, all and any liability whether arising in tort, contract or otherwise (save as referred to above) which they might otherwise be found to have in respect of this Prospectus or any such statement. No representation or warranty express or implied, is made by any of the Banks or any of their respective affiliates as to the accuracy, completeness, verification or sufficiency of the information set out in this Prospectus, and nothing in this Prospectus will be relied upon as a promise or representation in this respect, whether or not to the past or future.

In connection with the Global Offer, the Managers and any of their respective affiliates acting as an investor for its or their own account(s) may purchase Shares and, in that capacity, may retain, purchase, sell, offer to sell or otherwise deal for its or their own account(s) in such securities, any other securities of the Company or other related investments in connections with the Global Offer or otherwise. Accordingly, references in this Prospectus to Shares being offered, sold or otherwise dealt with should be read as including any offer to purchase or dealing by the Managers or any of them or any of their respective affiliates acting as an investor for its or their own account(s). In addition, certain of the Managers and any of their respective affiliates may in the ordinary course of their business activities enter into financing arrangements with investors in connection with which such Managers (or their affiliates) may from time to time acquire, hold or dispose of Shares. Morgan Stanley Senior Funding, Inc. is acting as underwriter, mandated lead arranger and bookrunner under the Senior Credit Facility (as defined herein). Bank Hapoalim is acting as underwriter, mandated lead arranger, bookrunner and onshore account bank under the Senior Credit Facility (as defined herein). Poalim Trust Services Ltd is acting as onshore security agent and original hedging bank under the Senior Credit Facility (as defined herein). Natixis is acting as underwriter, mandated lead arranger, bookrunner and joint technical bank under the Senior Credit Facility (as defined herein). Société Générale, London Branch, is acting as underwriter, mandated lead arranger, bookrunner, offshore security trustee and offshore account bank under the Senior Credit Facility (as defined herein). The Managers do not intend to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligation to do so.

Each of the Managers and their respective affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for, the Company and/or the Major Shareholders for which they would have received customary fees. Each of the Managers and their respective affiliates may provide such services to the Company and/or the Major Shareholders and any of its affiliates in the future.

Prospective investors should only rely on the information contained in this Prospectus. No person has been authorised to give any information or make any representations other than those contained in this Prospectus and, if given or made, such information or representation must not be relied upon as having been so authorised by the Company, the Directors or the Banks. In particular the content of the Company's website does not form part of this Prospectus and prospective investors should not rely on it. Without prejudice to any legal or regulatory obligation on the Company to publish a supplementary prospectus pursuant to Section 87G of the FSMA and Prospectus Rule 3.4, neither the delivery of this Prospectus nor Admission shall, under any circumstances, create any implication that there has been no change in the business or affairs of the Company since the date of this Prospectus or that the information in it is correct as of any time after the date of this Prospectus.

Persons who come into possession of this Prospectus should inform themselves about and observe any applicable restrictions and legal, exchange control or regulatory requirements in relation to the distribution of this Prospectus. Any failure to comply with such restrictions or requirements may constitute a violation of the securities laws of any such jurisdiction. The contents of this Prospectus should not be construed as legal, business or tax advice.

This Prospectus does not constitute or form part of any offer or invitation to sell or issue, or any solicitation of any offer to purchase or subscribe for, any securities other than the securities to which it relates or any offer or invitation to sell or issue, or any solicitation of any offer to purchase or subscribe for, such securities by any person in any circumstances in which such offer or solicitation is unlawful.

Notice to overseas shareholders

The Shares have not been, and will not be, registered under the U.S. Securities Act of 1933, as amended (the "**U.S. Securities Act**"). The Shares offered by this Prospectus may not be offered or sold in the United States, except to qualified institutional buyers ("**QIBs**"), as defined in, and in reliance on, the exemption from the registration requirements of the U.S. Securities Act provided in Rule 144A under the U.S. Securities Act ("**Rule 144A**") or another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. Prospective investors are hereby notified that the sellers of the Shares may be relying on the exemption from the provisions of section 5 of the U.S. Securities Act provided by Rule 144A. Outside of the United States, the Global Offer is being made in offshore transactions as defined in Regulation S of the U.S. Securities Act. No actions have been taken to allow a public offering of the Shares under the applicable securities laws of any jurisdiction, including Canada, Australia or Japan. Subject to certain exceptions, the Shares may not be offered or sold in any jurisdiction, or to any resident of Canada, or to or for the account or benefit of any national, resident or citizen of any other jurisdiction, including Australia or Japan. This Prospectus does not constitute an offer of, or the solicitation of an offer to subscribe for or purchase, any of the Shares to any person in any jurisdiction to whom it is unlawful to make such offer or solicitation in such jurisdiction.

The Shares have not been and will not be registered or qualified for distribution by this Prospectus under the applicable securities laws of Canada, Australia or Japan. Subject to certain exceptions, the Shares may not be offered or sold in any jurisdiction, or to or for the account or benefit of any national, resident or citizen in Australia or Japan or to any person located or resident in Canada. The Shares have not been recommended by any U.S. federal or state securities commission or regulatory authority. Furthermore, the foregoing authorities have not confirmed the accuracy or determined the adequacy of this Prospectus. Any representation to the contrary is a criminal offence in the United States.

The distribution of this Prospectus and the offer and sale of the Shares in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company, the Major Shareholders (as defined in Part 17 "*Definitions*") or the Banks to permit a public offering of the Shares under the applicable securities laws of any jurisdiction. Other than in the United Kingdom, no action has been taken or will be taken to permit the possession or distribution of this Prospectus (or any other offering or publicity materials relating to the Shares) in any jurisdiction where action for that purpose may be required or where doing so is restricted by law. Accordingly, neither this Prospectus, nor any advertisement, nor any other offering material may be distributed or published in any jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with such restrictions may constitute a violation of the securities laws of any such jurisdiction.

Available information

For so long as any of the Shares are in issue and are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act, the Company will, during any period in which it is not subject to section 13 or 15(d) under the U.S. Securities Exchange Act of 1934, as amended (the "**U.S. Exchange Act**"), nor exempt from reporting under the U.S. Exchange Act pursuant to Rule 12g3-2(b) thereunder, make available to any holder or beneficial owner of a Share, or to any prospective purchaser of a Share designated by such holder or beneficial owner, the information specified in, and meeting the requirements of, Rule 144A(d)(4) under the U.S. Securities Act.

Information to Distributors

Solely for the purposes of the product governance requirements contained within: (a) EU Directive 2014/65/EU on markets in financial instruments, as amended ("**MiFID II**"); (b) Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II; and (c) local implementing measures (together, the "**MiFID II Product Governance Requirements**"), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the Product Governance Requirements) may otherwise have with respect thereto, the Shares have been subject to a product approval process, which has determined that such Shares are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients and eligible counterparties, each as defined in MiFID II; and (ii) eligible for distribution through all distribution channels as are permitted by MiFID II (the "**Target Market Assessment**"). Notwithstanding the Target Market Assessment, Distributors should note that: the price of the Shares may decline and investors could lose all or part of their investment; the Shares offer no guaranteed income and no capital protection; and an investment in the Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Offer. Furthermore, it is noted that, notwithstanding the Target Market Assessment, the Managers will only procure investors who meet the criteria of professional clients and eligible counterparties. For the avoidance of doubt, the Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Shares. Each distributor is responsible for undertaking its own target market assessment in respect of the Shares and determining appropriate distribution channels.

This Prospectus is dated 16 March 2018.

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SUMMARY

Summaries are made up of disclosure requirements known as "Elements". These Elements are numbered in Sections A-E (A. 1—E. 7). This summary contains all the Elements required to be included in a summary for this type of security and issuer. Because some Elements are not required to be addressed, there may be gaps in the numbering sequence of the Elements.

Even though an Element may be required to be inserted in the summary because of the type of securities and issuer, it is possible that no relevant information can be given regarding the Element. In this case a short description of the Element is included in the summary with the mention of "not applicable".

Section A—Introductions and warnings

A.1 **Warning**

This summary should be read as an introduction to the Prospectus.

Any decision to invest in the securities should be based on consideration of the Prospectus as a whole by the investor. Where a claim relating to the information contained in the Prospectus is brought before a court, the plaintiff investor might, under the national legislation of the Member States of the European Economic Area, have to bear the costs of translating the prospectus before the legal proceedings are initiated.

Civil liability attaches only to those persons who have tabled this summary including any translation thereof, and applied its notification, but only if the summary is misleading, inaccurate or inconsistent when read together with the other parts of the Prospectus or it does not provide, when read together with the other parts of the Prospectus, key information in order to aid investors when considering whether to invest in such securities.

A.2 **Subsequent resale of securities or final placement of securities through financial intermediaries**

Not applicable. No consent has been given by the Company or any person responsible for drawing up this Prospectus to the use of the Prospectus for subsequent resale or final placement of securities by financial intermediaries.

Section B—Issuer

B.1 **Legal and commercial name**

Energean Oil & Gas plc (the "**Company**" and together with each of its consolidated subsidiaries and subsidiary undertakings from time to time, the "**Group**" or "**Energean**").

B.2 **Domicile and legal form**

The Company was incorporated on 8 May 2017 as a public limited company in England and Wales with the name Energean Oil & Gas plc and its registered office situated in England and Wales. The principal legislation under which the Company operates is the Companies Act 2006 and regulations made thereunder.

B.3 **Current operations and principal activities**

Energean is an independent oil and gas exploration and production company focused on the exploration, development and production of oil and gas assets in the Eastern Mediterranean, including Greece, Israel, the Adriatic and North Africa. Energean's strategy is to create a profitable and returns-focused business with sustainable growth by leveraging the Group's experience and expertise in identifying, acquiring, developing and operating oil and gas assets in this region. The Directors intend that the Company will, in due course, become the leading independent exploration and production company in the Eastern Mediterranean.

Since its establishment in 2007, Energean has acquired a diverse portfolio of producing assets, appraisal and development opportunities and exploration prospects and is the operator of the majority of the key

assets in its portfolio. Energean's total 2P reserves were 50.0 MMbbls of oil and 6.0 Bcf of gas and its total 2C resources were 55.8 MMbbls of oil and 2.4 Tcf of gas as of 31 October 2017 (including Karish and Tanin resources at 100%, of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement).

The current developed producing assets, Prinos and Prinos North, are offshore oil producing fields located in Greece. The Group produced on average approximately 2,803 bopd from the Prinos fields during the year ended 31 December 2017 (2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down), compared to 3,490 bopd during the year ended 31 December 2016. The Group has a future investment plan in the Prinos Basin from 2018 of approximately US$353 million to 2021 and approximately US$65 million from 2021 to 2034 underway to increase production.

The Group has development projects located in Israel and Greece. The Group's most significant undeveloped assets are the Karish and Tanin offshore gas fields located in Israel (which are currently 50% owned by each of Energean and Kerogen Capital). Karish and Tanin had an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of condensate and light oil (contingent 2C resources) as of 31 October 2017 (of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement).

B.4a **Significant recent trends affecting the Group and the industry in which it operates**

The recent trends affecting the Group and the oil and gas industry include:

- the increased level of oil production achieved by the Group from 2014 to 2016, increasing from an average of 1,409 bopd in 2014 to an average of 3,490 bopd in 2016. Production decreased to an average of 2,659 bopd for the ten month period ended 31 October 2017, and was 2,803 bopd (2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down) for the year ended 31 December 2017, reflecting asphaltene and drilling difficulties in the first half of 2017, which reduced production below previous projections. Exit rate production at 31 December 2017 was 4,086 bopd;
- the increase in the Group's total 2P oil reserves, from 30 MMbbls as of 31 December 2014 to 50.0 MMbbls as of 31 October 2017;
- the December 2016 acquisition of the Karish and Tanin offshore gas fields located in Israel (which are currently 50% owned by each of Energean and Kerogen Capital, with Energean Israel's share expected to increase to 70% subject to FID by 31 March 2018, pursuant to the Second EISL Subscription Agreement) for US$40.0 million closing payment with an obligation to pay contingent consideration of US$108.5 million (contingent upon the final investment decision of Energean Israel Limited or aggregated expenditures of US$150 million in connection with the leases) and royalties to the sellers, which as of 31 October 2017 had an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of condensate and light oil (contingent 2C resources) (of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement);
- the investment plan from 2018 of approximately US$353 million through 2021 and approximately US$65 million from 2021 to 2034 to increase production at Prinos;
- the intention to develop the Karish and Tanin offshore gas fields located in Israel, to be able to generate first gas sales in 2021; and
- continuing volatility in crude oil and gas prices, driven by a number of factors including the condition of the world economy and geopolitical events and technical advances affecting energy consumption and extraction methods.

B.5 **Group description**

The Company has been the main holding company of the Group since 30 June 2017. The previous holding company of the Group, Energean E&P Holdings Limited, is wholly owned by the Company and has the following principal subsidiaries:

- Energean Oil & Gas SA;

- Energean Israel Limited (currently as to 50.0001% voting rights, with the intention to increase this interest to 70% pursuant to the Second EISL Subscription Agreement, subject to taking FID by 31 March 2018);
- Energean Montenegro Limited;
- Energean International Limited; and
- Kavala Oil S.A.

B.6 **Major Shareholders**

As at the Latest Practicable Date prior to publication of this Prospectus and as expected immediately following Admission, the following persons held or are expected to hold an interest which represents 3% or more of the voting rights attached to the issued share capital of the Company, and the amount of such person's interest is as follows:

	As at the Latest Practicable Date		Immediately following Admission	
Shareholder	**Number of Shares**	**Percentage of issued share capital**	**Number of Shares**	**Percentage of issued share capital**
Third Point Hellenic Recovery (Lux) S.À R.L.	40,782,418	51.1%	40,782,418	26.7%
Growthy Holdings Co. Limited[(1)]	18,688,224	23.4%	19,437,816	12.7%
Oilco Investments Limited[(2)]	16,281,257	20.4%	17,819,893	11.7%
Adobelero Holdings Co. Ltd[(3)]	3,976,809	5.0%	4,055,713	2.7%
Clal Insurance	—	—	15,780,878	10.3%
Capital Research Global Investors	—	—	10,874,957	7.1%
Pelham Capital	—	—	7,251,942	4.7%
Kerogen	—	—	5,523,308	3.6%

Notes:

(1) Number of shares shown represents the aggregate shareholding of Mathios Rigas as an individual and his indirect holdings by virtue of his controlling interest in both Growthy Holdings Co. Limited and Capital Energy Investments Limited.

(2) Number of shares shown represents the aggregate shareholding of Efstathios Topouzoglou as an individual and his indirect holdings by virtue of his controlling interest in both Oilco Investments Limited and HIL Hydrocarbon Investments Limited.

(3) Number of shares shown represents the shareholding of Panos Benos by virtue of his controlling interest in Adobelero Holdings Co. Ltd.

None of the Shareholders detailed above have voting rights which differ in any way from those of the Company's other Shareholders. So far as the Company is aware, save as set out in the table above, no person has an interest which represents 3% or more of the issued share capital or voting rights of the Company, which would be notifiable under the Disclosure Guidance and Transparency Rules following Admission.

So far as the Company is aware, as of the Latest Practicable Date, there are no arrangements the operation of which may at a later date result in a change of control of the Company.

The Company is not aware of any person who either as of the date of this Prospectus or immediately following Admission exercises, or could exercise, directly or indirectly, control over the Company.

Each of Third Point Hellenic Recovery (Lux) S.À R.L., Growthy Holdings Co. Limited and Oilco Investments Limited will be a substantial shareholder of, a "person exercising significant influence" over, and a "related party" to, the Company for the purposes of the Listing Rules.

B.7 **Key financial information and narrative description of significant changes to financial condition and operating results of the Group during or subsequent to the period covered by the historical key financial information**

The selected financial information set out below has been extracted without material adjustment from the Consolidated Historical Financial Information relating to the Group included in Section B of Part 13 "*Consolidated Historical Financial Information*".

Consolidated statement of profit or loss
(Amounts in thousands US$, unless otherwise stated)

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Revenue	38,425	31,187	39,724	28,434	42,244
Cost of Sales	(36,363)	(31,574)	(40,551)	(32,128)	(32,279)
Gross profit (loss)	**2,062**	**(387)**	**(827)**	**(3,694)**	**9,965**
Administration expenses	(4,339)	(3,305)	(4,134)	(4,788)	(6,241)
Selling and distribution expenses	(313)	(267)	(336)	(308)	(298)
Exploration and evaluation expenses	(7,050)	(1,116)	(1,133)	(252)	(308)
Other income	2,169	558	248	265	26,192
Other expenses	(9,770)	(1,735)	(4,688)	(3,061)	(7,482)
Operating profit (loss)	**(17,241)**	**(6,252)**	**(10,870)**	**(11,838)**	**21,828**
Finance Income	14	323	327	91	166
Finance Costs	(21,132)	(20,997)	(29,311)	(20,138)	(18,283)
Gain on derivative	24,109	—	—	—	—
Net foreign exchange gain/(loss)	27,621	499	(10,043)	(12,116)	(10,191)
Profit (loss) from continuing operations before tax	**13,371**	**(26,427)**	**(49,897)**	**(44,001)**	**(6,480)**
Taxation (expense) / income	(8,776)	7,066	11,517	10,581	(7,317)
Profit (loss) from continuing operations	**4,595**	**(19,361)**	**(38,380)**	**(33,420)**	**(13,797)**
Discontinued operations					
Profit/(loss) from discontinued operations	(1,403)	(108)	(229)	(66)	(104)
Profit (loss) for the period	**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**
Attributable to:					
Owners of the parent	3,201	(19,469)	(38,608)	(33,468)	(10,270)
Non-controlling Interests	(9)	—	(1)	(18)	(3,631)
	3,192	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**

Consolidated statement of financial position
(Amounts in thousands US$, unless otherwise stated)

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Total non-current assets	313,098	263,169	260,634	220,818	170,981
Total current assets	124,442	61,248	83,652	24,688	37,098
Total assets	**437,540**	**324,417**	**344,286**	**245,506**	**208,079**
Total equity	**282,889**	**1,154**	**(16,120)**	**20,099**	**59,326**
Total non-current liabilities	92,222	279,277	265,509	197,585	124,837
Total current liabilities	62,430	43,986	94,897	27,822	23,916
Total Liabilities	**154,652**	**323,263**	**360,406**	**225,407**	**148,753**
Total Equity and Liabilities	**437,540**	**324,417**	**344,286**	**245,506**	**208,079**

Consolidated statement of cash flows
(Amounts in thousands US$, unless otherwise stated)

	For the ten months ended 31 October		For the year months ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Cash flows from / (used in) operations	**23,440**	**3,881**	**15,309**	**(2,392)**	**17,422**
Tax paid	—	—	—	(28)	—
Payments in relation to provisions	—	—	(74)	(344)	(291)
Net cash from / (used in) operating activities	**23,440**	**3,881**	**15,235**	**(2,764)**	**17,131**
Net cash used in investing activities	**(48,655)**	**(55,386)**	**(108,844)**	**(49,126)**	**(35,683)**
Net cash from financing activities	**17,202**	**67,918**	**103,056**	**46,024**	**23,405**
Net increase / (decrease) in cash and cash equivalents	8,013	16,413	**9,447**	**(5,865)**	**4,853**
Cash and cash equivalents at beginning of the period	17,586	8,238	8,238	14,327	11,286
Effect of exchange rate fluctuations on cash and equivalent	(910)	(9)	(99)	(224)	(1,812)
Cash and cash equivalents at end of the period	**8,663**	**24,642**	**17,586**	**8,238**	**14,327**

Certain significant changes to the Group's financial position and results of operations occurred during the years ended 31 December 2014, 2015 and 2016 and the ten month period ended 31 October 2017.

The Group's revenue increased by US$11.3 million, or 39.7%, to US$39.7 million in the year ended 31 December 2016, from US$28.4 million in 2015, primarily as a result of increased oil sales resulting from the drilling of new wells in the Prinos area that came on stream in 2016 and which led to a 96.5% increase in sales volume to 1.1 MMbbls in 2016, compared to 0.6 MMbbls in 2015. The Group's revenue had previously decreased by US$13.8 million, or 32.7%, to US$28.4 million in the year ended 31 December 2015 from US$42.2 million in the year ended 31 December 2014, primarily as a result of a decline in oil prices in the period.

In August 2016 (subject to certain conditions being met), Energean Israel acquired an interest in the lease of the Karish and Tanin fields in Israel for a US$40 million initial and closing payment, with ongoing obligations to pay to the sellers an additional US$108.5 million over ten years as well as ongoing royalties. The Group, in conjunction with its strategic partner, Kerogen Capital, intends to further invest approximately US$1.6 billion in Phase 1 capex (plus an additional US$371 million in other costs, including deferred payments) to develop the fields for gas production with first gas expected in 2021.

The Group's revenue increased by US$7.2 million, or 23.2%, to US$38.4 million in the ten month period ended 31 October 2017 as compared to US$31.2 million in the ten month period ended 31 October 2016, primarily as a result of a 19.6% increase in realised crude oil sales to US$36.6 million in the first ten months of 2017 from US$30.6 million in the same period in 2016.

Between May 2017 and February 2018, the Group signed 12 gas sale and purchase agreements relating to Karish and Tanin to supply gas in an estimated aggregate amount, following initial commissioning and transition periods, of an average of approximately 4.2 billion cubic meters per annum on an annual contract quantity basis (or 3.1 BCM per annum on a take or pay basis), excluding the Or Gas Supply Agreement (up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis or approximately 3.3 to 3.8 BCM per annum on a take or pay basis including the Or Gas Supply Agreement), assuming, inter alia, 95% uptime and reasonable maintenance.

In December 2017, the Group signed an US$88.3 million EPCIC contract with GSP Offshore S.R.L. for drilling and construction related to the Epsilon development program, including the Lamda production facilities and three development wells.

In 2017, Energean Israel participated in Israel's First Offshore Bid Round. Energean submitted bids for block 12 (which sits between the Karish and Tanin leases) and four additional adjacent blocks, including blocks 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and awards were announced on 12 December 2017, with Energean receiving all five of the additional licences for which it had bid.

On 28 December 2017, Energean Israel, Energean E&P Holdings, the Founders and Kerogen entered into the Second EISL Subscription Agreement, based on commercial terms agreed in October 2017, pursuant to which Energean E&P Holdings agreed to subscribe for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash. This sum includes the amount payable in respect of Energean's carry of 20% of Energean Israel for US$80 million, together with its 70% proportionate share of funding in respect of such carry. Upon completion of such subscription, Energean E&P Holdings would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018 (or 30 June 2018 if Kerogen so consents).

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities—a facility of up to US$105 million with EBRD and the Black Sea Trade and Development Bank as lenders and a US$75 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders. Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP EPCIC Contract. The facility is secured by substantially all of the assets of EOGSA and a guarantee from Energean E&P Holdings and a pledge of its shares in EOGSA. The facility will have a seven-year tenor.

On 2 March 2018, Energean Israel entered the US$1.275 billion Senior Credit Facility underwritten by a club of Israeli and international banks for the purposes of, amongst other things, financing the development of the Karish field, paying debt service (other than principal) and paying deferred payments due from Energean Israel to Delek and Avner pursuant to the terms of the sale and purchase agreement entered into on 16 August 2016 in respect of Karish and Tanin and made between Delek, Avner and Energean Israel.

On 2 March 2018, Energean Israel, Technip UK Limited, Technip France SA and Technip Ships One Limited agreed an approximately US$1.36 billion (multi-currency) lump-sum turnkey engineering, procurement, construction, installation and commissioning contract relating to the development of the Karish field.

Other than the above, there has been no significant change in the financial position or results of operations of the Group since 31 October 2017, the date to which the last audited consolidated financial information of the Group was prepared.

B.8 **Key pro forma financial information**

The unaudited consolidated pro forma statement of net assets set out below has been prepared to illustrate the effects of the Reorganisation and the Global Offer on the net assets of the Group had the Reorganisation and the Global Offer taken place on 31 October 2017.

The pro forma financial information is based on the consolidated statement of financial position of the Group as at 31 October 2017 contained in Section B of Part 13 of this Prospectus. The Pro forma financial information has been prepared in a manner consistent with the accounting policies applied in preparing the Consolidated Historical Financial Information set out in Section B of Part 13, the basis set out in the notes below and in accordance with the requirements of items 1 to 6 of Annex II of the Prospectus Directive Regulation.

The pro forma financial information has been prepared for illustrative purposes only, and by its nature addresses a hypothetical situation and, therefore, does not reflect the Group's actual financial position or results. It may not therefore give a true picture of the Group's financial position or results, nor is it indicative of the results that may or may not be achieved in the future.

		Pro forma adjustments		
	Consolidated net assets of the Group at 31 October 2017	Net proceeds of the Global Offer	Reorganisation	Consolidated pro forma statement of net assets of the Group as at 31 October 2017
	US$'000			
	(Note 1)	(Note 2)	(Note 3)	
ASSETS				
Non-current assets				
Property plant and equipment	290,318	—	—	290,318
Intangible assets	3,616	—	—	3,616
Investments in Joint Ventures	—	—	101,615	101,615
Other non-current assets	575	—	—	575
Deferred tax asset	16,761	—	—	16,761
Bank deposits	1,828	—	—	1,828
Total non-current assets	**313,098**	**—**	**101,615**	**414,713**
Current assets				
Inventories	14,276	—	—	14,276
Trade and other receivables	11,716	—	—	11,716
Derivative asset	91,615	—	(91,615)	—
Cash and cash equivalents	6,835	447,500	(10,000)	444,335
Total current assets	**124,442**	**447,500**	**(101,615)**	**470,327**
Total assets	**437,540**	**447,500**	**—**	**885,040**
LIABILITIES				
Non-current liabilities				
Borrowings	79,186	—	—	79,186
Deferred tax liabilities	3,732	—	—	3,732
Provisions for liabilities	6,749	—	—	6,749
Trade and other payables	2,555	—	—	2,555
Total non-current liabilities	**92,222**	**—**	**—**	**92,222**
Current liabilities				
Trade and other payables	54,607	—	—	54,607
Current tax liabilities	2,605	—	—	2,605
Provisions for liabilities	5,218	—	—	5,218
Total current liabilities	**62,430**	**—**	**—**	**62,430**
Total liabilities	**154,652**	**—**	**—**	**154,652**
Net assets	**282,888**	**447,500**	**—**	**730,388**

Notes:

(1) The net assets of the Company have been extracted without adjustment, from the Consolidated Historical Financial Information as set out in Section B of Part 13 of this Prospectus. As at 31 October 2017, the net assets of the Company amounted to US$282.9 million, represented by issued ordinary share capital of US$0.9 million as set out in Section B of Part 13 "*Consolidaed Historical Financial Information*".

(2) As set out in Section 1 of Part 15 of this Prospectus the total net proceeds received by the Company from the Global Offer are estimated to be approximately US$447.5 million, after deduction of transaction related costs of US$12.5 million.

(3) On Admission and pursuant to the terms of the Reorganisation, the Company agreed to acquire 50% of the EISL Class B Shares of Energean Israel Limited from its Founders for US$10 million in cash. On completion of the acquisition of the EISL class B shares of Energean Israel Limited (a contingent purchase obligation arising through the Reorganisation) the Group will derecognise the fair value of the obligation (US$91.6 million derivative asset at 31 October 2017). The combined amount of the cash payment and derecognition of the obligation is presented as an investment in Joint Venture. For the Pro Forma this combined amount is US$101.6 million based on the amounts at 31 October 2017, whereas the actual amount will reflect the fair value of the derivative asset as at the actual date of derecognition of the derivative asset.

Additional Information

This Pro forma financial information does not constitute financial statements within the meaning of section 434 of the Companies Act 2006.

On 28 December 2017, Energean E&P Holdings, Energean Israel, the Founders and Kerogen entered into the Second EISL Subscription Agreement, pursuant to which the Energean E&P Holdings agreed to subscribe for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash. Upon completion of such subscription, the Group would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018. The effect of such subscription has not been reflected in the Pro forma financial information as it will take place subsequent to Admission.

On Admission and pursuant to the terms of the Reorganisation, the Energean International Preference Shares held by Third Point will be converted to common shares in the Company. This conversion solely impacts equity and non-controlling interests and has no impact on net assets. As a result, this transaction has not been reflected in the Pro forma financial information. The reorganisation on Admission is discussed in paragraph 3.1 of Part 9 "*Reorganisation in connection with Admission*" of this Prospectus.

The Pro forma financial information does not reflect any changes in the trading position of the Group or any other changes arising from other transactions, other than those outlined in the above notes, since 31 October 2017.

B.9 **Profit forecast**

Not applicable. There is no profit forecast or estimate included in this Prospectus.

B.10 **Nature of any qualifications in the audit report on the Consolidated Historical Financial Information**

Not applicable. There are no qualifications to the accountant's report on the Consolidated Historical Financial Information included in this Prospectus.

B.11 **Insufficient working capital**

Not applicable. In the opinion of the Company, taking into account the net proceeds receivable by the Company from the Global Offer and the bank and other facilities available to the Group, the Group has sufficient working capital for its present requirements, that is, for at least the next 12 months following the date of this Prospectus.

Section C—Securities

C.1 **Type and class of securities**

Pursuant to the Global Offer, the Company intends to issue 72,592,016 New Shares, raising proceeds of approximately £330 million (approximately US$460 million), before underwriting commissions and other estimated fees and expenses of approximately £9 million. The New Shares will represent approximately 48% of the expected issued ordinary share capital of the Company immediately following Admission.

When admitted to trading, the Shares will be registered with ISIN number GB00BG12Y042 and SEDOL number BG12Y04, and will trade under the ticker symbol "ENOG".

C.2 **Currency of the securities issue**

Pounds Sterling.

C.3 **Number of securities to be issued**

As at the Latest Practicable Date, the issued share capital of the Company is £802,312.22, comprising 80,231,222 Shares of £0.01 each (all of which were fully paid). Immediately following completion of the Global Offer, the issued share capital of the Company is expected to be £1,528,232.38 comprising 152,823,238 Shares of £0.01 each (all of which will be fully paid on Admission).

C.4 **Description of the rights attaching to the securities**

The Shares being issued pursuant to the Global Offer will, on Admission, rank *pari passu* in all respects with the other Shares in the issued share capital of the Company. Holders of Shares have the following rights:

- right to receive notices of general meetings of the Company;
- right to attend any general meeting of the Company and vote at such meetings;
- right to receive the Company's financial statements;
- right of at least five shareholders present in person or by proxy or any shareholder(s) that represent not less than 10% of the total voting rights to demand a poll at the Company's general meeting;
- right to receive dividends if declared; and
- in the case of a shareholder that holds a minimum of 10% of the Company's share capital, the right to requisition an extraordinary general meeting.

C.5 **Restrictions on the free transferability of the securities**

Not applicable. There are no restrictions on the free transferability of the Shares.

C.6 **Admission to trading**

Application has been made to the FCA for all of the Shares, issued and to be issued in connection with the Global Offer, to be admitted to the premium listing segment of the Official List of the FCA and to the London Stock Exchange for such Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

C.7 **Dividend policy**

The Directors do not expect that Energean will pay any dividends until after the completion of the development of, and first gas from, the Karish and Tanin fields, and in any event until such time as it is prudent to do so, having regard to the level of revenue generated by the Group's operations and the retained earnings to fund its operations and exploration and development programmes.

Section D—Risks

D.1 **Key information on the key risks specific to the Group and the oil and gas industry**

The occurrence of any of the key risks below could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

The Group's business strategy depends significantly on the successful development of the Karish and Tanin offshore gas fields in Israel, which are currently only at the preliminary stages of development. There is currently no infrastructure in place at the Karish and Tanin fields and certain regulatory approvals are also pending. Should these or other milestones not be achieved, the Group may be unable to successfully develop Karish and Tanin. Even if development progresses, there can be no assurance that such development will not be subject to significant delays or cost overruns or that the expected production or sales volumes for the fields can be achieved. The approval of the field development plan for Karish and Tanin is subject to challenge by a petition submitted by two Israeli environmental groups and another petition by a regional council. If the first petition is granted in the environmental groups' favour, the approval of the field development plan could be revoked and the new approval procedure for the field development plan would be expected to involve significant delay. In addition, there can be no assurance that any re-approval would be granted or as to the conditions of any such re-approval or any consequential increased costs. If the second petition is granted, the Group would need to seek approval of the National Council, which, if modifications to the FDP were required, would require re-approving the FDP. There could also be other adverse effects on the Group's business as a result of delays, uncertainty or increased costs.

The development of the Karish and Tanin fields requires the Group to arrange substantial financing, and the Group may be unable to complete the development within the budget currently contemplated. The successful conclusion of the Global Offer and funding under the Senior Credit Facility are required in order to ensure sufficient funding for Phase 1. Utilisation of funds under the Senior Credit Facility is subject to a number of conditions, including satisfaction of a projected debt service coverage ratio of 1.5:1, an equity contribution of US$465.8 million in aggregate by the Group and Kerogen, approval of the Karish Lease Environmental Document by the Israeli Petroleum Commissioner and maintenance of a debt to equity ratio of no greater than 66:34.

The Group faces intense competitive pressure in the domestic Israeli gas market where several companies are operating and developing assets, some of whom have more experience in the Israeli market as well as greater estimated production than the Group. The Group could face intense competition in securing domestic gas sales contracts and there may be an oversupply of gas to the Israeli market and a corresponding decrease in gas prices. The Group also faces competition in the wider oil and gas industry where there is competition for, among other things, the acquisition of exploration and production licences, the engagement of third party service providers and the employment of experienced employees and management.

The Group's business depends significantly on the level of oil prices, which are volatile, and could be adversely affected by a substantial or extended decline in oil prices. Oil prices have in the past fluctuated widely due to a multitude of global, regional and national macroeconomic conditions and, as oil is globally traded, the Group has no control over the prices it receives for the oil it produces.

The Group is currently dependent on a single area, the Prinos basin in Greece, for the entirety of its current oil and gas production and depends on revenue from these fields to fund its operations and service its existing debt. The Group is therefore disproportionately exposed to any disruptions, loss of licences, delays or interruptions to operations in the Prinos basin.

The Group's exploration and production operations are dependent on its compliance with obligations under contracts, licences, permits, operating agreements and relevant legislation. Should the Group fail to comply with such obligations, fines may be imposed or damages claimed against the Group and leases may be suspended or terminated.

The Group's operations require significant capital expenditure, and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain and the costs of obtaining such funding may be significant. The Group may also enter into significant borrowing to finance future growth and the Group's existing debt obligations could increase the cost of, or limit the Group's ability to obtain, such additional borrowings.

The Group faces significant uncertainties in connection with its exploration, appraisal and development activities, and it may discover or produce less oil or gas than anticipated. The Group is currently in the exploration phase in relation to several of its assets, and there can be no guarantee that expenditure on exploration activities will result in the discovery of commercially deliverable oil or natural gas. In addition, due to the uncertainty of appraisal results for discoveries, there can be no assurance that the Group's appraisal and development activities will result in the targeted outcome. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. The Group may, therefore, be unable to convert contingent resources at any of its undeveloped fields into reserves. Similarly, prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative.

The level of the Group's crude oil and gas reserves and resources and their quality and production values are inherently uncertain and may be lower than estimated or expected. If the assumption upon which the estimates of the Group's oil and gas reserves and resources have been based prove to be incorrect, or if the actual reserves or resources available to the Group are otherwise less than the current estimates or of a lesser quality than expected, the Group may be unable to recover and produce the estimated levels or quality of oil, gas and other hydrocarbons set out in this Prospectus.

All of the Group's production of crude oil from the Prinos basin is currently sold to BP Oil International Limited under a long-term offtake agreement. The Group is therefore currently reliant on BP Oil International Limited for substantially all of its revenue and hence subject to the increased risk of delayed payment for delivered production volumes, counterparty default or termination of the sales agreement by BP Oil International Limited. If the offtake agreement was terminated by action of either party, the Group

would need to negotiate and enter into a new contract with another purchaser for the sale of its oil from the Prinos basin.

D.3 **Key information on the key risks specific to the securities**

There is no existing market for the Shares and an active trading market for the Shares may not develop or be sustained. Moreover, even if a market develops, Shares may be subject to market price volatility and the market price of the Shares may decline disproportionately in response to developments that are unrelated to the Group's operating performance, or as a result of sales of substantial amounts of such Shares in the public markets, for example following the expiry of the lock-up period, or the issuance of additional Shares in the future, and shareholders could earn a negative or no return on, or otherwise experience a dilution, of their investment in the Company.

The Major Shareholders will retain a significant interest in and will continue to exert substantial influence over the Group following the Global Offer and their interests may differ from or conflict with those of other shareholders.

Shareholders in the United States and other jurisdictions may not be able to participate in future equity offerings.

Section E—Global Offer

E.1 **Net proceeds and costs of the Global Offer**

Pursuant to the Global Offer, the Company expects to receive net proceeds of approximately £321 million (approximately US$448 million), after underwriting commissions and other estimated total fees and expenses of approximately £9 million.

No expenses will be charged by the Company to any investor who purchases Shares pursuant to the Global Offer.

E.2a **Reasons for the Global Offer and use of proceeds**

The Directors believe that the Global Offer will:

- provide funding required for investment in the Group's development projects and organic growth of the existing producing asset base; and
- further increase the Group's profile and brand recognition.

The Company expects to raise gross proceeds of approximately £330 million (approximately US$460 million) in the Global Offer, of which:

- approximately US$405 million will be used to fund investment in the development of the Karish and Tanin gas fields offshore Israel, including the US$80 million carry payable by Energean E&P Holdings to increase its interest in Energean Israel to 70% (as part of the consideration payable under the Second EISL Subscription Agreement);
- US$10 million will be used to repay, at face value, a bridge investment from the Founders used to contribute to the acquisition costs of the Karish and Tanin assets;
- approximately US$13 million will be used for IPO transaction fees and expenses; and
- approximately US$32 million will be used for exploration capital expenditure and other corporate purposes.

E.3 **Terms and conditions of the Global Offer**

The Global Offer consists of an institutional offer only. In the Global Offer, Shares will be offered (i) to certain institutional investors in the United Kingdom and elsewhere outside the United States in reliance upon Regulation S and (ii) in the United States only to QIBs in reliance on Rule 144A or pursuant to another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act.

The Shares allocated under the Global Offer have been fully underwritten, subject to certain conditions, by the Underwriters. Allocations under the Global Offer will be determined at the sole discretion of the Company and the Major Shareholders after having received a recommendation from the Joint Global Co-ordinators. All Shares issued pursuant to the Global Offer will be issued, payable in full, at the Offer Price.

Conditional dealings in the Shares are expected to commence on the London Stock Exchange at 8.00 a.m. (London time) on 16 March 2018. The earliest date for settlement of such dealings will be 21 March 2018. It is expected that Admission will become effective, and that unconditional dealings in the Shares will commence on the London Stock Exchange, at 8.00 a.m. (London time) on 21 March 2018. Settlement of dealings from that date will be on a two-day rolling basis.

E.4 **Material interests**

Not applicable. There are no interests, including conflicting interests, that are material to the Global Offer, other than those disclosed in B.6 above.

E.5 **Selling shareholders and lock-up arrangements**

Not applicable. There are no existing Shares being sold in the Global Offer. The New Shares will be offered by the Company.

Lock-up Arrangements

Pursuant to the Underwriting Agreement, the Company has agreed that, subject to certain exceptions, during the period of 180 days from the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, issue, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein or in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

Pursuant to the Underwriting Agreement and related arrangements, Third Point has agreed that, subject to certain exceptions, during the period of 180 days from the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

Pursuant to the Underwriting Agreement and related arrangements, the Founders, the Directors and certain members of the Company's management team have agreed that, subject to certain exceptions, during the period of 360 days from the date of Admission, they will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

E.6 **Dilution**

Pursuant to the Global Offer, existing Shareholders will experience a 48% dilution from the issue of 72,592,016 New Shares (i.e. its, his or her proportionate interest in the Company will drop by 48%).

E.7 **Expenses charged to the investor**

Not applicable. No expenses will be charged by the Company to any investor who subscribes for or purchases Shares pursuant to the Global Offer.

PART 1
RISK FACTORS

Any investment in the Shares is subject to a number of risks. Prior to investing in the Shares, prospective investors should carefully consider risk factors associated with any investment in the Shares, the Group's business and the industry in which it operates, together with all other information contained in this Prospectus including, in particular, the risk factors described below.

Prospective investors should note that the risks relating to the Group, its industry and the Shares summarised in the section of this Prospectus headed "Summary" are the risks that the Directors and the Company believe to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in the section of this Prospectus headed "Summary" but also, among other things, the risks and uncertainties described below.

The risk factors described below are not an exhaustive list or explanation of all risks which investors may face when making an investment in the Shares and should be used as guidance only. Additional risks and uncertainties relating to the Group that are not currently known to the Group, or that the Group currently deems immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects and, if any such risk should occur, the price of the Shares may decline and investors could lose all or part of their investment. Prospective investors should consider carefully whether an investment in the Shares is suitable for them in the light of the information in this Prospectus and their personal circumstances.

1. Risks relating to the Group's business and industry

1.1 The Group's business strategy depends significantly on the successful development of the Karish and Tanin offshore gas fields in Israel, which are currently only at a preliminary stage of development

The Group's business strategy depends significantly on the successful development of the Karish and Tanin offshore gas fields in Israel (the "**Karish-Tanin Development**"). However, as of the date of this Prospectus, these fields remain at a very preliminary stage of development, with essentially no infrastructure yet in place and substantial cooperation still required from third parties, including certain regulatory approvals by the Israeli Petroleum Commissioner. The Group intends to follow a phased development of these fields in accordance with its field development plan ("**FDP**"), which was approved by the Israeli Petroleum Commissioner in August 2017 (currently subject to judicial challenge—see "*—The approval of the FDP in respect of the Karish-Tanin Development is subject to challenge*"), with the first phase ("**Phase 1**") involving the construction of a floating production storage and offloading ("**FPSO**") facility, the drilling of three wells in the Karish main field to be connected to the FPSO and the construction of a production manifold near the wells and a 90km dry gas pipeline. The Group anticipates that Phase 1 will require an investment of approximately US$1.6 billion in Phase 1 capex (plus an additional US$371 million in other costs, including deferred payments), which is to be financed through borrowings comprising a secured, syndicated senior credit facility of up to US$1.275 billion (the "**Senior Credit Facility**"), expected deferred payments (post-2021) of US$140 million in respect of the Technip EPCIC Contract (as defined below) and related US$125 million standby letter of credit, and equity financing of approximately US$465.8 million to be provided by the Group and Kerogen Capital ("**Kerogen**") in proportion to their interests in Energean Israel Limited ("**Energean Israel**" or "**EISL**"), the associate which holds the lease interests for Karish and Tanin. The Group's proportion of this equity financing, expected to be in the amount of approximately US$405 million, is to be funded from the proceeds of the Global Offer. The Group does not control Kerogen and any delay in or failure by Kerogen to arrange such financing could lead to a delay in the development of the fields or ultimately to a failure to develop the fields successfully. See also "*The Group relies on the participation of its partner, Kerogen, in Energean Israel and must obtain Kerogen's consent to significant matters affecting Energean Israel's operations*".

To date, the Group has entered into gas sale and purchase agreements with various purchasers (the "**Gas Supply Agreements**"), under which, subject to all conditions being satisfied, the Group expects to supply gas in an aggregate amount, following initial commissioning and transition periods, of approximately 4.2 billion cubic meters ("**BCM**") per annum on an annual contract quantity ("**ACQ**") basis (or 3.1 BCM per annum on a take or pay basis), excluding the Or Gas Supply Agreement (or up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis or approximately 3.3 to 3.8 BCM per annum on a take or pay basis including the Or Gas Supply Agreement), assuming, inter alia, 95% uptime and reasonable maintenance. Sales to the purchasers will be from the point at which Karish begins to produce at commercial levels for a period of around 14 to 18 years (up to

20 years in the case of Or Power) and for a period of approximately 7 years for the Supergas Gas Supply Agreement. The Gas Supply Agreements may become subject to termination and any applicable damages if the Group for any reason fails to start producing gas at commercial levels by the end of 2021. Accordingly, any delay in the development of the fields could result in a failure ultimately to develop the fields successfully.

The Karish-Tanin Development remains subject to substantial risks and uncertainties, and no assurance can be given that the Group will be able to successfully develop them or, even if successfully developed in due course, that their development will not be subject to significant delays and cost overruns or that the Group will ultimately be able to achieve expected production or sales volumes. Such risks and uncertainties include the following:

- conversion of the contingent resources of Karish and Tanin into reserves (see *"—The level of the Group's crude oil and gas reserves and resources and their quality and production volumes are inherently uncertain and may be lower than estimated or expected*"), particularly in light of the fact that the Group has not undertaken any production tests at the fields to date, which could also lead to unanticipated technical or other difficulties which could limit production and/or sales volumes (see also "*—The Group faces significant uncertainties in connection with its exploration, appraisal and development activities, and it may discover or produce less oil or gas than expected*");
- the Group's lack of experience operating in Israel, which has a developing oil and gas regime and poses greater geopolitical operational and security risks, as compared to Greece (see also "*—Risks relating to the countries in which Energean operates—The geopolitical situation in Israel may adversely affect the Group's business*");
- reliance on third parties for the construction of significant infrastructure. For example, the Group intends to rely on TechnipFMC for construction of the FPSO and subsurface facilities in the Karish field under an approximately US$1.36 billion (multi-currency) lump sum, turnkey engineering, procurement, construction, installation and commissioning ("**EPCIC**") contract (the "**Technip EPCIC Contract**") (see also "*Failure to obtain necessary equipment, third party services and infrastructure systems could materially and adversely affect the Group's business, results of operations, financial condition and/or prospects*");
- cooperation from third parties in connection with significant operational decisions and funding. The Group's strategic partner Kerogen, for example, retains consent rights with respect to significant matters affecting Energean Israel's operations and, as noted above, the Group is reliant on Kerogen to arrange substantial financing for the development of the Karish and Tanin fields (see also "*The Group relies on the participation of its partner, Kerogen, in Energean Israel and must obtain Kerogen's consent to significant matters affecting Energean Israel's operations*"); and
- the development of the Karish and Tanin fields requires the Group to arrange substantial financing, and the Group may be unable to complete the development within the budget currently contemplated. The successful conclusion of the Global Offer and funding under the Senior Credit Facility are required in order to ensure sufficient funding for Phase 1. Utilisation of funds under the Senior Credit Facility, which is expected to occur no earlier than the fourth quarter of 2018, is subject to a number of conditions, including satisfaction of a projected debt service coverage ratio of 1.5:1, an equity contribution of US$465.8 million in aggregate by the Group and Kerogen, approval of the Israeli Petroleum Commissioner of documentation prepared by Energean Israel, in accordance with certain specific Israeli governmental guidelines, and which contains the analysis of the results of the offshore environmental baseline survey (the "**Karish Lease Environmental Document**") and maintenance of a debt to equity ratio of no greater than 66:34 (see also "*The Group's operations require significant capital expenditure, and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain and the costs of obtaining such finance may be significant*" and "*The Group is leveraged and is subject to restrictive debt covenants and security arrangements that may limit its ability to finance its future operations and capital needs and to pursue business opportunities and activities. Breach of financial covenants may lead to default and/or liquidity risk*").

Any of the foregoing risks and uncertainties regarding the Karish-Tanin Development could result in delays to the completion of Phase 1 on the expected timetable or at all and lead to greater competition from other gas providers (including the Leviathan gas field, which is expected to begin producing commercial volumes of gas by the end of 2019), unexpected and potentially significant cost increases, regulatory penalties due to non-compliance with lease milestones and/or contractual damages or early termination under the Gas Supply Agreements if it is unable to deliver gas and complete the determined project development milestones by the relevant long-stop date under such Gas Supply Agreements, any of which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.2 The Group will be generally prohibited from exporting Karish and Tanin gas production outside of Israel and as a result is subject to risks and uncertainties in the domestic Israeli gas market

Under the terms of the applicable leases and those of the sale and purchase agreement pursuant to which the Group obtained its lease interests in the Karish and Tanin fields, the Group is prohibited from exporting gas produced from the Karish and Tanin fields and is limited to selling this gas solely to the domestic Israeli market. As a result, the Group is particularly exposed to risks and uncertainties in the domestic Israeli gas market, including risks relating to demand for gas and electricity, oversupply and competition in the Israeli domestic market.

Domestic natural gas production in Israel has been a relatively recent development as the country has begun to transform the structure of its energy sector to become increasingly self-sufficient, including converting its power plants from fuel oil and coal to gas and developing offshore Israeli gas fields. While domestic electricity tariffs are subject to regulatory determinations set at the discretion of the regulator, the price of gas is not currently regulated; however, gas producers must notify the Israeli Minister of Energy regarding prices and profitability, and there can be no assurance that the Israeli Minister of Energy would not decide to impose price regulation on gas in the future.

There are several companies operating and developing assets in the emerging domestic market, with gas production in Israel currently subject to export quotas in accordance with the size of each field. The Group will compete with Noble Energy Mediterranean Ltd ("**Noble**"), Delek Drilling Limited Partnership ("**Delek**"), Isramco Negev 2 LLP ("**Isramco**"), Dor Gas Exploration ("**Dor**") and Everest Infrastructures Limited Partnership ("**Everest**") as holders of the Tamar field (with Noble as operator), and with Delek, Noble and Ratio Oil Exploration ("**Ratio**"), as holders of the Leviathan field (with Noble as operator), which is expected to begin producing by the end of 2019. Each of these other producers has more experience than the Group in operating in the Israeli market and could therefore have a competitive advantage, particularly as estimated production from the Tamar and Leviathan fields is expected to be significantly higher than production from the Karish and Tanin fields. Any inability of the Group's competitors to sell gas production outside of Israel at acceptable prices, whether as a result of quotas, logistical difficulties, supply and demand dynamics (including as a result of competition or oversupply from discoveries outside of Israel) or otherwise, could lead to oversupply to the domestic Israeli gas market and a decrease in gas prices, which could be detrimental to the Group.

In addition, domestic demand for gas in Israel is expected to be driven in large measure by demand for electricity; therefore, any decrease in demand for electricity could have a corresponding negative impact on demand for gas in the Israeli market generally to the extent not covered by any minimum offtake requirements, such as those included in the Gas Supply Agreements. Such a decrease in demand could arise as a result of a weakening of economic conditions in Israel, development of alternative sources of electricity (such as solar or other renewable sources) or unexpected political or military risks in Israel. See also "*—Risks relating to the countries in which Energean operates—The geopolitical situation in Israel may adversely affect the Group's business"*.

The occurrence of any of the foregoing could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.3 The Group will be dependent on the purchasers under its Gas Supply Agreements

The Gas Supply Agreements which the Group has to date entered into include take-or-pay arrangements under which the purchasers must accept or pay for a minimum amount of natural gas from the Group, following initial commissioning and transition periods, totalling an average of approximately 3.0 to 3.8 BCM per year on a take or pay basis (assuming, inter alia, 95% uptime and reasonable maintenance and depending on whether Or Power Energies (Dalia) Ltd. ("**Or Power**") completes the development of a new power generation facility and reaches financial closing, as described below) at a price linked predominantly to the Israeli electricity production component index but with a small percentage (less than 5%) of the contracted quantity indexed to oil and in each case underpinned by a floor price. Once the Group begins to produce gas in Israel, it will be dependent on these purchasers for regular and prompt payment of amounts owed for the gas the Group supplies under the Gas Supply Agreements and is therefore exposed to the risk of default by these purchasers. In the event of such a default (in particular by IC Corporation affiliated entities (representing approximately 54% to 62% of the aggregate annual contract quantity ("**ACQ**"), depending on whether the Or Power project is completed)), the Group could be required to find other purchasers for its gas, potentially on less favourable terms than under the Gas Supply Agreements. See also Part 5 "*Business Overview—Offtake and marketing—Gas Supply Agreements*".

The amount of gas in respect of which Energean Israel is paid under the Gas Supply Agreements is variable and depends on a number of factors.

The Gas Supply Agreement with one of Energean Israel's customers, Or Power, representing up to approximately 15% of the Group's aggregate ACQ for Karish and Tanin, depends on Or Power succeeding in its application to receive a new licence from the Electricity Authority to construct a new power generation plant in Israel and successfully completing this project. The Electricity Sector Law and its regulations provide that purchasers such as Or Power are required to obtain a conditional production licence in order to be able to construct its proposed power generation plant, to be replaced by a permanent production licence following its commercial operation. Any applicant for a conditional licence must demonstrate certain conditions which were prescribed in the regulations, inter alia, the feasibility of the connection of its proposed power station to the electricity transmission network, that it has the required financial capacity (a minimum requirement of injection of 20% equity to the project) and to demonstrate its rights on the land where such power station is planned to be constructed. In addition, the Electricity Authority decides whether to grant conditional production licences based on the regulatory framework in place regarding each technology and the quotas determined therein. See also Part 7 *"Regulatory Overview—Regulatory and Legislative Framework in Israel—Government Regulations—Regulatory Framework for Conventional IPPs"*. While the Directors believe this will occur, there can be no guarantee that Or Power will be successful in its licence application, that the project will be completed successfully or that Or Power will reach financial closing as set out in the Or Power Gas Supply Agreement, in which case Energean Israel may not make any gas sales or receive any payment for gas under the Or Gas Supply Agreement, which would reduce the total amount of gas purchasers must accept or pay for under the Gas Supply Agreements to an average of approximately 3.0 to 3.3 BCM per year (following initial commissioning and transition periods and assuming, inter alia, 95% uptime and reasonable maintenance). Any such reduction in the total amount of gas purchasers must accept or pay for under the Gas Supply Agreements would have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

In addition, the Gas Supply Agreements with I.P.P. Alon Tavor Ltd., I.P.P. Ramat Gavriel Ltd. and OPC Hadera Ltd. (regarding certain quantities), representing, together, approximately 11% of the Group's aggregate ACQ for Karish and Tanin, relate to the supply of gas to power generation facilities currently under construction. Based on information from such customers, Energean expects their facilities to begin commercial operations in 2018 or 2019, but there can be no assurance that these customers will successfully complete construction of the generation facilities or begin commercial operations on schedule or at all. In the event that such customers do not commence commercial operations or commercial operations were significantly delayed, revenue from such contracts may not be realised when expected, the Gas Supply Agreements with such customers may be terminated under certain conditions or such customers may be unable to fulfil their obligations under the Gas Supply Agreements.

Under the Gas Supply Agreements, Energean Israel is not entitled to a take or pay payment during the period in which Energean Israel's or the customer's facilities (if applicable) are being commissioned (the "**Commissioning Period**"), though Energean Israel will receive payment at the contract price for any gas consumed by such customers during such period.

The Gas Supply Agreements are subject to various conditions precedent in addition to those noted above, including, among others, a timely final investment decision and financing of the Karish and Tanin development by Energean Israel, the consent of certain buyers' existing lenders, shareholder approvals of certain buyers (including the IC Corporation affiliated entities) and obtaining certain consents from the Israeli antitrust authority (conditions precedent vary for each Gas Supply Agreement). There can be no assurance that the conditions precedent to the Gas Supply Agreements will be satisfied in a timely manner or at all. In the event that the conditions precedent to any of the Gas Supply Agreements were not fully satisfied, such contract may fail to come into force or be terminated, which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. See also Part 5 "*Business Overview—Offtake and marketing—Gas Supply Agreements*".

Several of the Gas Supply Agreements provide for supply of a "daily contract quantity" ("**DCQ**") of gas within a range, with the final DCQ to be determined by a contractual or regulatory notice from the customer in relation to its consumption from other suppliers and resultant obligation to Energean Israel to contract for the maximum volume such mechanism allows based on the three years' actual average consumption preceding such notice. In addition, the Gas Supply Agreements with Ramat Negev, Ashdod, Ramat Gabriel and Alon Tavor, representing, together, approximately 11% of the Group's aggregate contracted quantity for Karish and Tanin, allow customers to reduce their DCQ by approximately 30% in the event that a customer's facility fails to qualify as a "production unit in cogeneration" as defined in the Israeli Electricity Sector Regulations (Cogeneration) 2004 (the "**Cogeneration Regulation**") and as a result become subject to section 7(c) of such regulation. Should such customers exercise such rights in the future, total gas volumes sold may decline and could be lower than the gas sales volumes assumed in the Group's projections.

While the Gas Supply Agreements contain a take-or-pay mechanism whereby customers commit to taking or paying for specified quantities of gas, such take or pay quantities may vary from year to year with the application of the carry forward or make-up mechanisms set out in the Gas Supply Agreements, such that the take or pay quantity may, in any one year, with such adjustments, fall below the average take or pay quantity set out in the Gas Supply Agreements. This may occur insofar as quantities of gas were paid for but not taken (make-up) or taken and paid for in previous years in excess of the take or pay quantity (carry forward). Thus the take or pay mechanism neither ensures payment for gas at the ACQ levels specified in the contracts nor in any given year does it ensure payment in respect of the average take or pay amounts. Rather, the take or pay mechanism provides for a minimum quantity of gas relative to ACQ only over the life of the Gas Supply Agreements.

Contract prices under the Gas Supply Agreements are predominantly linked to the Israeli electricity production component index, which is set by Israeli authorities and periodically revised based on electricity production costs of Israel Electric Corporation ("**IEC**"), with a small percentage (less than 5%) of the contracted quantity indexed to oil. Should the Israeli electricity production component index decline in a given period, the contract prices the Group receives for gas sales under the Gas Supply Agreements would decline, which would negatively impact the Group's revenues and results of operations. In addition, while the contract prices under the Gas Supply Agreements are supported by a specified floor price, the floor price provided in respect of certain entities, representing approximately 14% of the Group's aggregate ACQ, may reduce by approximately 5% from the initial floor price should the Israeli electricity production component index drop below a specified threshold. Contract prices for certain buyers are also partially linked to the exchange rate between the US dollar and the New Israeli Shekel. An adverse change in this exchange rate would reduce the contract price received for gas sales under such Gas Supply Agreements, which would adversely affect the Group's revenues and results of operations.

The Gas Supply Agreements include provisions for early termination rights for the purchasers due to a failure by the Group to achieve certain milestones or satisfy certain conditions by their due date, extended force majeure, acts of insolvency and breach of material obligations under the Gas Supply Agreements. In addition, there can be no assurance that, should the Gas Supply Agreements be terminated or terminate, the Group will be able to negotiate extensions to the agreements or else find new purchasers for the gas it produces, on commercially viable terms or at all. The occurrence of any of the foregoing could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. For further information on the Gas Supply Agreements, see *"Business Overview—Offtake and Marketing—Gas Supply Agreements"*.

1.4 The Group's current business depends significantly on the level of oil prices, which are volatile, and could be adversely affected by a substantial or extended decline in oil prices

The Group's current business depends significantly upon prevailing oil prices, which may be adversely impacted by unfavourable global, regional and national macroeconomic conditions. As oil is globally traded, the Group is unable to control the prices it receives for the oil it produces. Currently, all oil which the Group produces is sold to BP Oil International Limited ("**BP**") under an offtake agreement (the "**BP Offtake Agreement**") which applies further market price differentials to the price the Group receives for its oil. See "*All of the Group's production of crude oil from the Prinos basin is currently sold to BP under a long-term offtake agreement. Any changes to, disagreements in respect of or termination of this offtake agreement may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects*".

Oil prices are volatile and have recently declined significantly. Historically, prices for oil and gas have fluctuated widely for many reasons, including:

- changes in global and regional supply and demand, and expectations regarding future supply and demand, for oil and gas products;
- geopolitical uncertainty;
- weather conditions and natural disasters;
- access to pipelines, storage platforms, shipping vessels and other means of transporting and storing oil and gas;
- prices, availability and government subsidies of alternative and/or renewable energy sources;
- prices and availability of new technologies;
- increasing government regulations and actions and international treaties and agreements which aim to reduce the environmental impact of greenhouse gases and increased expenditure for producers to comply with such regulations, actions, treaties and agreements;

- changes in availability of, and access to, pipeline ullage;
- the ability and willingness of the members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices;
- political, economic and military developments in oil producing regions generally, and domestic and foreign governmental regulations and actions, including import and export restrictions, taxes, repatriations and nationalisations;
- proximity to, and the capacity and cost of, transportation;
- petroleum refining capacity;
- global and regional economic conditions;
- supply chain inflationary pressures;
- trading and speculative activities by market participants and others either seeking to secure access to oil and gas or to hedge against commercial risks, or as part of investment portfolio activity; and
- terrorism, war or the threat thereof, which may affect supply, transportation or demand for hydrocarbons and refined petroleum products.

It is difficult to predict accurately future oil and gas price movements. Historically, crude oil prices have been highly volatile and subject to large fluctuations in response to relatively minor changes in the demand for oil. Price volatility was particularly prominent in 2014. The second half of 2014 saw crude oil prices drop sharply, primarily due to a supply surplus resulting from, among other factors, increased oil production in North America and OPEC countries. According to Bloomberg, during 2014, the maximum and minimum prices for dated Brent crude oil were US$115.06/bbl and US$57.33/bbl, with an average price of US$99.45/bbl. In 2015, dated Brent crude oil prices continued to decline, with maximum and minimum prices of US$67.77/bbl and US$36.11/bbl and an average price of US$53.60/bbl in 2015. In 2016, dated Brent crude oil prices decreased further, with maximum and minimum prices of US$56.82/bbl and US$27.88/bbl and an average price of US$45.13/bbl. In 2017, Brent crude oil peaked at US$67.02/bbl (26 December 2017) and the lowest price was US$44.82/bbl (21 June 2017). Prices fell from a monthly average high of US$56.00/bbl in February to a low of US$47.55/bbl for the month of June, recovering in the second half of the year with an average price in 2017 of US$54.75/bbl.

Although the Group's gas revenues from Israel will be priced on a long term contract basis, linked to domestic electricity prices and subject to minimum price protection, and thus not directly exposed to fluctuations in traded gas or oil linked liquefied natural gas ("**LNG**") pricing other than in the case of renewals or entry into additional Gas Supply Agreements, the crude oil and condensate produced from the Karish and Tanin fields will still be subject to price volatility for the reasons set out above.

A reduction in expected future oil and gas prices may also result in a reduction in the volumes of the Group's resources which can be expected to be produced commercially, resulting in decreases to its reported reserves and resources. The Group may also elect not to produce from certain assets at lower prices, or its commercial partners may not want to continue production regardless of the Group's position. All of these factors could result in a material decrease in the Group's net production revenue, causing a reduction in its oil and gas exploration and development activities and reserves and resources. In addition, certain development projects could become unprofitable as a result of a decline in oil prices and could result in the Group having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with a negative economic impact on the Group. Further, a reduction in oil prices may lead to the Group's producing fields being shut down and entry into the decommissioning phase earlier than estimated. The occurrence of any of the foregoing could have a material adverse impact on the Group's business, results of operations, financial condition and/or prospects.

1.5 The Group's current production is concentrated in one area, the Prinos basin in Greece, and production delays or interruptions could impair the Group's results of operations

Although the Group owns and operates various undeveloped and exploration assets, the Group's current oil and gas production and related revenue are obtained entirely from the Prinos basin, located offshore in northeast Greece. The assets in the Prinos basin currently rely on offshore platforms, a pipeline and an onshore processing facility, all of which is owned by the Greek government and granted for the exclusive use of the Group for the term of the Group's licence in the area. The Group currently sells all of its oil produced in the Prinos basin to BP under the BP Offtake Agreement, as described under "*All of the Group's production of crude oil from the Prinos basin is currently sold to BP under a long-term offtake agreement. Any changes to, disagreements in respect of or termination of this offtake agreement may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects*".

The Group depends on revenue from these fields to fund its operations and service its existing debt and will continue to depend on this revenue, and the anticipated increased revenue as a result of its targeted increase in production, in the near to medium term to fund the exploration and development activities necessary for the realisation of its business strategy in Greece.

As a result of this concentration, the Group is disproportionately exposed to the effect of disruption, loss of licence or interest in assets of the Prinos basin, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, equipment failure, aging facilities and infrastructure, personnel or services market limitations, labour disputes, weather events, or interruption of the processing or transportation of oil. The Group may be exposed to additional risks, such as changes in applicable rules and regulations that could cause the Group to permanently or temporarily shut-in all of its wells within the Prinos basin. Unexpected or additional well maintenance, for example as a result of excessive build-up of asphaltene, wax or other precipitates or generally as a result of the operation of aging infrastructure, could lead to diminished production, increased costs and failure to reach its intended production target. For example, production in Prinos basin has historically experienced asphaltene precipitation, and during 2017 production in Prinos basin was reduced in order for the Group to carry out the appropriate work-over activities. Although the Group has taken measures to improve production efficiency and prevent excessive build-up of asphaltene, no assurance can be given that the Group will not experience additional production difficulties in the future or that the Group will be able to address any production difficulties encountered in the future in a timely or cost-effective manner, all of which could hamper the Group's targeted production increase from its oil fields in the Prinos basin.

If delays or interruptions in production at these assets occur due to such risks and circumstances, or if the Group's interests in such assets were to be terminated or reduced, or the BP Offtake Agreement terminated, the Group's ability to generate revenue could be harmed, which could in turn have a material adverse effect on its business, results of operations, financial condition and/or prospects. Additionally, failure to achieve its increased production targets could have a material adverse effect on its growth strategy and ability to fund further exploration and development opportunities.

1.6 All of the Group's production of crude oil from the Prinos basin is currently sold to BP under a long-term offtake agreement. Any changes to, disagreements in respect of or termination of this offtake agreement may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects

The Group has entered into the BP Offtake Agreement to sell all of its crude oil produced in the Prinos basin, its only currently producing asset, to BP. Under the terms of this offtake agreement, oil is sold at a price determined by a formula which includes a fixed market differential as well as an option for BP to elect a reference price based on the current month or the prior month at its sole discretion. As a result of this formula, the Group's average realised price per barrel represented a discount to Brent of US$7.46 in 2017, US$9.53 in 2016, US$8.82 in 2015 and US$3.05 in 2014. The Group is therefore currently reliant on BP for substantially all of its revenue and hence subject to the increased risk of delayed payment for delivered production volumes, counterparty default or suspension or termination of the sales agreement by BP. The BP Offtake Agreement provides BP with termination rights in certain situations, including where there has been a breach of health, safety, security and environmental standards by the Group which risks material harm to BP's reputation or there has been a failure by the Group to comply with its delivery obligations. For further information, see Part 6 *"Business Overview—Offtake and marketing—BP Offtake Agreement"*. If the offtake agreement was terminated by action of either party, the Group would need to negotiate and enter into a new contract with another purchaser for the sale of its oil from the Prinos basin. During any such negotiations, which may take a significant amount of time to conclude, the Group may not be able to sell any of its oil from the Prinos basin, which would have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.

While the Directors believe that the Group would be able to secure alternative purchasers for the oil currently produced by the Group if needed, there can be no assurance that the Group would be able to negotiate and enter into agreements with purchasers for the sale of oil on equivalent terms to those with BP, or at all. Any such delays, defaults, reduction in oil volumes purchased or adverse pricing or other contractual terms could adversely affect the Group's business, results of operations, financial condition and/or prospects.

1.7 The Group's exploration and production operations are dependent on its compliance with obligations under contracts, licences, permits, operating agreements and relevant legislation

The Group's exploration and development operations must be carried out in accordance with the terms of its concession agreements, oil exploration, development and production licences and leases, and applicable annual

work programmes, field development plans and budgets as established in relation thereto (collectively, "**Leases**"). Under the terms of the Group's Leases, as well as applicable legislation, fines may be imposed or damages claimed and a Lease may be suspended or terminated if a Lease holder or party to the contract fails to (i) comply with its obligations under such Lease or agreement; (ii) make timely payments of levies and taxes for the licensed activity; (iii) provide required technical or financial information; or (iv) meet other reporting requirements. The extent of such obligations may be unclear or ambiguous, and regulatory authorities in jurisdictions in which the Group operates may not confirm that such work obligations have been fulfilled, which can lead to operational uncertainty.

In addition, the Company's subsidiaries and associates have obligations to develop the fields in accordance with the specific requirements under the applicable Leases, laws and regulations. If they were to fail to satisfy such obligations with respect to a specific field, the Lease for that field may be suspended, revoked or terminated. In some instances, the Group may be jointly and severally liable for required payments pursuant to the terms of the Leases under which it operates.

Exploration Leases and related agreements pursuant to which the Group operates typically have a limited life before the Group is obliged to seek to extend the exploration period, convert the Lease to a production licence or relinquish the Lease area. While the Group would normally seek approval from the appropriate authorities to transition to subsequent phases of the relevant Lease or convert such Lease to a production licence, there can be no assurance that such transitions or conversions will be granted with respect to expired Leases or that the administrative and regulatory process will not have an adverse effect on the Group's business and operations.

Each of the Group's exploration and production Leases have incorporated within them detailed work programmes which have to be fulfilled and normally within a specified timeframe. These may include seismic surveys to be performed, wells to be drilled, production to be attained, and construction matters, amongst other things. There are also obligations under Leases to carry out drilling operations for the purpose of discovering and exploiting deposits in addition to those delivered under the relevant Lease. Failure to comply with any of these obligations may result in regulatory penalties and/or damages claimed against the Group. Absent any farm-out or other arrangements, the Group bears the responsibility and risk for these drilling operations (including the obligation to fully restore and plug the relevant wells).

The authorities in the countries in which the Group operates can, and do from time to time, inspect the Group's and its commercial partners' compliance with its Leases and relevant laws. There can be no assurance that the views of the relevant government agencies regarding the development of the Group's and its commercial partners' fields or compliance with the terms of the Leases will coincide with the Group's views, which might lead to disagreements that cannot be resolved.

If oil and/or gas is discovered during the exploration Lease term, the Group is required to apply for a production licence before commencing production. If the Group complies with the terms of the relevant Lease then it would normally expect that a production licence would be issued. For example, in Greece, when a leaseholder submits sufficient evidence that a discovery is commercially exploitable, the exploitation stage begins as a matter of law and an agreement is reached on the delimitation of the exploitation area. However, no assurance can be given that the necessary production licences will be granted by the relevant authorities.

The Leases may also be modified or withdrawn by sovereign authorities, notwithstanding the terms of such agreements, as a result of changes in law, public policy or the politics of such countries. There can be no assurances that the terms of any of the Leases would not be changed to impose more onerous requirements on the Group or to alter the economic terms to be less favourable to the Group.

The suspension, revocation or termination of any Lease or related agreements pursuant to which the Group operates or delays in the continuous development of or production at the Group's fields caused by the issues detailed above may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. In addition, failure to comply with the obligations under the Leases, whether inadvertent or otherwise, may lead to fines, penalties, restrictions, withdrawal of licences and termination of related agreements, which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.8 The Group's operations require significant capital expenditure, and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain and the costs of obtaining such finance may be significant

The Group's business involves significant capital expenditure, and it may require external debt and further equity financing in order to fund expenditure beyond its current committed and planned capital expenditure. The Group

anticipates that it will need to make substantial capital investments for its operations, exploration, appraisal, development and/or production plans. The Group has, for example, an anticipated capital investment, in relation to the investment in the Israeli assets of Karish and Tanin, of approximately US$1.6 billion in Phase 1 capex (plus an additional US$371 million in other costs, including deferred payments) to fund Phase 1 of development to the commencement of gas production, which is expected in 2021. Thereafter, the development of Tanin and Karish North is anticipated to require investment of approximately US$1.0 billion in the period 2024 to 2031. Additional projected capital expenditures of approximately US$142 million are planned on the Group's assets in Greece and Montenegro and US$6.2 million on the recently acquired blocks 12, 21, 22, 23 and 31 offshore Israel for the year ending 31 December 2018. In order to meet these capital expenditure requirements, the Group plans to use the net proceeds of the Global Offer to be received by the Company together with its existing cash resources, debt facilities (including the Senior Credit Facility) and operating cash flow.

The Group may also enter into significant borrowing arrangements in addition to raising further equity financing for its operations, exploration, appraisal, development or production plans or any future acquisitions. The Group may also, in the future, seek funds for its business by selling part of its operations and/or by farming out its assets. There is no certainty that it will successfully identify counterparties willing to enter into such transactions in the future.

Should the Group seek to take on additional borrowings to finance future growth, the Group's existing debt obligations could increase the cost of or limit the Group's ability to obtain such additional borrowings, which in turn could have a material adverse effect on the Group's business, results of operations and financial condition. A variety of factors, some of which are outside of the Group's control (including, but not limited to, the global credit environment then existing), may mean that the Group may be unable to obtain debt financing or additional equity financing in the amounts required for its expenditures beyond its current committed capital expenditure, on favourable terms or at all.

If the Group fails to generate or obtain sufficient resources to fund its capital expenditure for its operations, exploration, appraisal, development or production plans (beyond the Group's current committed capital expenditure), this could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects or the Group's ability to fund the expansion or development of the business in the longer term.

1.9 The Group operates in a highly competitive industry

The oil and gas industry is highly competitive including in the region in which the Group operates. The key areas in respect of which the Group faces competition are:

- acquisition of exploration and production licences at auctions or sales run by governmental authorities;
- acquisition of other companies that may already own licences or existing hydrocarbon producing assets;
- engagement of third party service providers whose capacity to provide key services may be limited;
- purchase of capital equipment that may be scarce; and
- employment of the best qualified and most experienced skilled management and oil professionals.

The oil industry itself is currently subject to several important influences that impact its competitive landscape. In recent years, the oil industry has experienced consolidation, as well as increased deregulation and integration in strategic markets. Additionally, the expansion of production from shale oil fields in the United States in recent years has contributed to greater supply in world oil markets. The Group's ability to remain competitive will consequently require, among other things, management's continued focus on reducing unit costs, improving efficiency and maintaining long-term growth in the Group's reserves and production through efficient operational performance, field development and/or acquisition of new licences and assets.

The oil and gas industry is also characterised by rapid and significant technological advancements and the introduction of new products and services, including alternative and renewable fuel resources, using new technologies. As others use or develop new technologies, the Group may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before the Group can. The Group may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies the Group uses now or in the future were to become obsolete, the Group's business, results of operations, financial condition and/or prospects could be materially adversely affected. In addition, any new technology that the Group implements may have unanticipated or unforeseen adverse consequences, either to its business or the industry as a whole.

In Israel in particular, where the Group is limited to selling gas produced from the Karish and Tanin fields solely to the domestic Israeli market, and gas exports by its competitors are limited, the Group may face competition to obtain domestic gas supply contracts. Without an ability to export gas, the Group may be forced to compete with other gas producers in Israel and in the region on the basis of price and volume, limiting the revenue and profitability and potentially the economic viability of the Group's Israeli operations. See "*The Group is generally prohibited from exporting Karish and Tanin gas production outside of Israel and as a result is subject to risks and uncertainties in the domestic Israeli gas market*".

Any failure by the Group to compete effectively could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.10 The Group faces significant uncertainties in connection with its exploration, appraisal and development activities, and it may discover or produce less oil or gas than expected

Exploration activities are capital intensive and their successful outcome cannot be assured. The Group undertakes exploration activities and incurs significant costs with no guarantee that such expenditure will result in the discovery of commercially deliverable oil or natural gas. The Group is currently at the exploration phase in respect of its Leases for the Aitoloakarnania and Ioannina onshore areas in Greece and offshore Blocks 26 and 30 in Montenegro. Additionally, the Group has recently been awarded licences in respect of Blocks 12, 21, 22, 23, and 31 offshore Israel adjacent to Karish and Tanin. Due to the relatively short history of the Group, having been formed in 2007, the Group does not have any proven exploration success.

The Group's oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenue to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. Dry wells, or wells in which less oil and/or gas has been discovered than expected, may also result in the Group requiring substantially more funds if it chooses to continue exploration work and drill further wells beyond the Group's existing minimum exploration work. Such funding may be unavailable or may have to be obtained on unfavourable terms, leading to a potential deterioration in the Group's financial position. Drilling a dry well or discovering less oil and/or gas than expected would also mean that the Group may not be able to recover the costs incurred in drilling that well or make a return on its investment resulting in significant exploration expenditure being written off.

Should the Group undertake drilling in a particular geographic area but discover no oil and gas or discover less oil and/or gas than expected or be required to utilise more expensive drilling techniques and supporting infrastructure to extract oil in commercial quantities, this may lead to a downgrading of the potential value of the licence concerned and perhaps to other licences within the same geological basin.

Appraisal results for discoveries are uncertain. Appraisal and development activities involving the drilling of wells across a field may be unpredictable and not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of the entire field be fully understood. The Group is currently undertaking the Karish-Tanin Development in Israel, and to date it has not conducted any production tests in respect of those fields. The Group is also developing the Epsilon and Katakolo fields in Greece. There can be no assurance that the Group will be able to convert contingent resources at any of its undeveloped fields into reserves.

The Group's long term future success depends on its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. While the Group's current reserves are being depleted by production, unsuccessful exploration activities, such as dry wells, would mean that the Group would not be able to replace such reserves and the Group's revenue would decline. The Group may not be able to find or acquire additional reserves at acceptable costs which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

The Group will continue to gather data about its new venture opportunities and other projects. Additional information which comes to light could cause the Group to alter its schedule or determine that a new venture opportunity or project should not be pursued, which could adversely affect the Group's prospects.

1.11 The level of the Group's crude oil and gas reserves and resources and their quality and production volumes and expected cash flows are inherently uncertain and may be lower than estimated or expected

The reserves and resources information described in this Prospectus represents estimates only and is based on reports prepared by technical experts, being Netherland, Sewell & Associates, Inc. ("**NSAI**"), and does not

reflect events and activities subsequent to the relevant report dates. In general, estimates of economically recoverable reserves and resources and the future revenue therefrom are inherently uncertain, as they are based on a number of factors and assumptions made as of the date on which the reserves and resources estimates were determined, such as geological and engineering estimates (which have inherent uncertainties), historical production from the properties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results.

Estimation of underground accumulations of hydrocarbons which cannot be measured in an exact manner is a subjective process aimed at understanding the statistical probabilities of recovery. Estimates of the quantity of economically recoverable oil and gas reserves, rates of production, net present value of future cash flows and the timing of development expenditures depend upon several variables and assumptions, including the following:

- production history compared with production from other comparable producing areas;
- quality and quantity of available data;
- interpretation of the available geological and geophysical data;
- effects of regulations adopted by governmental agencies;
- future oil and gas prices;
- capital expenditure;
- effectiveness of the applied technologies and equipment;
- future operating costs, tax, development costs and workover and remedial costs; and
- the judgment of the persons preparing the estimates.

As all reserve estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities and qualities that are ultimately recovered;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred;
- the amount and timing of additional exploration and future development expenditures; and
- future oil and gas sales prices.

The Group utilises a range of techniques to estimate the quantity of economically recoverable oil and gas reserves. One of these techniques is the use of 2D and 3D data which, even when properly used and interpreted, may not identify accurately the presence of oil and gas. 2D and 3D seismic data and visualisation techniques are tools that assist geoscientists in identifying subsurface structures and hydrocarbon indicators, but do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of multi-dimensional seismic and other advanced technologies may involve significant pre-drilling expenditure, and the Group could incur losses as a result of such expenditure.

Many of the factors in respect of which assumptions are made when estimating reserves are beyond the Group's control, and therefore these may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration and appraisal drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves or resources data. Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenue and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material.

The uncertainties in relation to the estimation of reserves summarised above also exist with respect to the estimation of resources. The probability that contingent and/or prospective resources will be discovered, or be economically recoverable, is considerably lower than for proven, probable and possible reserves. Volumes and values associated with contingent and/or prospective resources should be considered highly speculative.

Certain resources relating to the Karish-Tanin Development detailed in the NSAI Israeli CPR contained in this Prospectus are classified as contingent resources, which under the Petroleum Resources Management System are designated as resources which are discovered and sub-commercial, pending certain contingencies. As such, there is a lower chance of commerciality attached to the cash-flows in the NSAI Israeli CPR which are associated with contingent resources than if they were classed as reserves.

Approximately 92% of the contingent resources covered by the NSAI Israeli CPR are subject to only two contingencies—namely project sanctioning and the availability of project financing. The financing for Phase 1 of the Karish-Tanin Development, principally comprising the Senior Credit Facility and a portion of the proceeds of the Global Offer, will be in place as of the date of Admission. The project sanctioning condition will be satisfied at the point that the Group proceeds with the final investment decision, which is in the control of the Group and is expected to take place within 30 days following Admission. The Directors believe that, on satisfaction of the above two contingencies, these contingent resources will satisfy the criteria to be classified as reserves. The Group intends to commission an update of the NSAI Israeli CPR as of 30 June 2018, at which point it currently anticipates that these contingent resources will be re-classified as reserves. Any delay in the Group proceeding to final investment decision would mean that these contingent resources would not be re-classified as reserves until such time as final investment decision was taken to proceed with the Karish-Tanin Development. In addition, the contingent resources in the Karish Field B Sand (which represent the remaining approximately 8% of the contigent resources covered by the NSAI Israeli CPR) are further contingent upon sufficient flow testing to establish commercial productivity.

The reserves and resources information set out and referred to in this Prospectus may not reflect actual reserves and resources or be comparable to similar information reported by other companies. If the assumptions upon which the estimates of the Group's oil and gas reserves and resources have been based prove to be incorrect, or if the actual reserves or resources available to the Group are otherwise less than the current estimates or of a lesser quality than expected, the Group may be unable to recover and produce the estimated levels or quality of oil, gas and other hydrocarbons set out in this Prospectus, which may have a material and adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.12 Failure to obtain or access necessary equipment, raw materials, third party services and infrastructure systems could materially and adversely affect the Group's business, results of operations, financial condition and/or prospects

The Group uses independent contractors to provide it with certain technical assistance and services, most notably Archer and Schlumberger for provision of drilling services related to the drilling campaign at Prinos basin, GSP Offshore S.R.L. for drilling and construction services related to the development of the Epsilon field pursuant to an EPCIC contract signed in December 2017 and TechnipFMC, with which the Group entered into a lump sum, turnkey EPCIC contract in March 2018 for the provision of the FPSO and all subsurface facilities for the Karish-Tanin Development. In Greece in particular, none of the service providers on which the Group relies have established service centres located in Greece, which requires the Group to rely on service centres located in other European countries, which may in turn limit the availability, delay the provision, and/or increase the costs, of such services.

Oil and natural gas development and exploration activities are dependent upon the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for specialised equipment such as drilling units or access restrictions may affect the availability of such equipment to the Group and may delay or create additional costs in the Group's development and exploration activities. However, it should be noted that the current low oil prices have led to greater availability and lower pricing of certain equipment. The Group may also be exposed to changes in the prices, or the availability, of raw materials such as chemicals used on the offshore platforms. Material increases in the price of raw materials, a lack of their availability, or increases in the costs of drilling activities, may increase the Group's cost of production or prevent the Group from undertaking further drilling in certain fields (for example, the Tanin field in Israel), which could have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.

The Group also contracts or leases services and capital equipment from third party providers. Unavailability or high costs of such services and equipment could result in a delay or restriction in the Group's projects and adversely affect the feasibility and profitability of such projects, and therefore have an adverse effect on the Group's business, results of operations, financial condition and/or prospects. Additionally, should such a third party provider default on, delay in fulfilling or become unable to fulfil its obligations under any such contracts or leases, the Group's ability to deliver projects on time and/or profitably could be impacted which could have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.

Particularly in Israel, the Group is also dependent on the integrity of the national transmission system since the Group's planned pipeline (which will be used for sales gas) will connect to the national transmission system operated by Israel Natural Gas Lines Ltd ("**INGL**"), a government-owned corporation responsible for Israel's gas transmission infrastructure. Energean and INGL have agreed a design for this gas pipeline. The Group is

awaiting the issuance of a transmission licence under article 10 of the Natural Gas Sector Law by the Minister of Energy. As permitted under the Israeli Government Decision 2592 (the "**Protection Decision**"), the Group and INGL are in the final stages of negotiating the principles regarding the terms and provisions of an agreement with respect to the financing and subsequent transfer of the last approximately 10km of the gas pipeline to be constructed by Energean and thereafter planned to be transferred to, and operated by, INGL following start-up of production from the FPSO. The Group will therefore be dependent on INGL for the ongoing operation of this part of the pipeline, which will then form part of the national transmission system, upon its transfer to INGL. The Group will have no control over any delay or pipeline unavailability which could prevent the Group from satisfying its gas supply obligations under the Gas Supply Agreements, and there can be no assurance that the Group could obtain adequate recourse from INGL in such an event. See also "*Risks relating to the countries in which Energean operates—The natural gas industry in Israel is under development and the Group will be dependent on government-owned and operated infrastructure to deliver its gas"*. Energean and INGL are also negotiating a connection agreement regarding the connection of the Group's planned pipeline and the national transmission system. Any delay in the construction and/or operation of any INGL pipeline to which the Group's pipeline connects would delay and/or prevent the Group from delivering gas to the domestic market which could have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.

For its assets in the Prinos basin in Greece, the Group relies to a limited extent upon transportation systems owned and operated by a related party, Seven Maritime Company ("**Seven Marine**"), which provides use of the Energean Wave to transport personnel to the offshore facilities, and the Valiant Energy, which is used to transport construction and maintenance materials, on a time-charter basis. The Group also relies on third parties for transportation purposes at its assets in Israel, Western Greece and Montenegro. The Group may be unable to access these or alternative transportation systems or could be subject to increased tariffs imposed by such third parties for transportation. Failure by the Group to secure necessary equipment, raw materials, third party services, pipeline access and other infrastructure systems could adversely affect the Group's business, results of operations, financial condition and/or prospects.

1.13 The approval of the FDP in respect of the Karish-Tanin Development is subject to challenge

The FDP approval is the subject of two petitions (the "**Petitions**") currently pending before the Israeli Supreme Court, summarised below.

First Petition

On 14 September 2017 the Society for the Protection of Nature in Israel and the Society of Man, Nature and Law, two of the leading local environmental groups in Israel (the "**First Petitioners**"), filed a petition (the "**First Petition**") in the Israeli Supreme Court against the Ministry of Energy, the Ministry of Environmental Protection, the Planning Administration in the Ministry of Finance and Energean Israel, seeking the revocation of the approval by the Israeli Petroleum Commissioner of the FDP in respect of the Karish-Tanin Development, in order to follow the First Petitioners' preferred procedure, under which certain elements of the Planning and Building Law, 5725-1965 (the "**Israeli Planning and Building Law**") would be applied to the approval process of the FDP. To date, the Israeli government approach has been not to apply the Planning and Building Law outside Israel's territorial waters, in its exclusive economic zone ("**EEZ**") where both the Karish and Tanin Leases are located. This approach is maintained in the Marine Bill, which seeks to create certainty by specifying an exhaustive list of local laws that apply in the EEZ and which does not apply the Planning and Building Law in the EEZ. The Marine Bill has been formally published as a bill and submitted to the Israeli Parliament and has recently passed the first out of three votes and is currently being prepared for the second and third parliamentary votes. See "*Regulatory Overview—Regulatory and legislative framework in Israel—Government Regulations—The Marine Bill*".

The approval procedure proposed by the First Petitioners would involve the Group preparing and publishing an environmental impact survey in accordance with the Israeli Planning and Building Law (in addition to the environmental requirements under the Petroleum Law and the applicable terms of the Leases for Karish and Tanin) and a subsequent public review period, a hearing and an approval of a National Planning Institution, prior to approval by the Petroleum Commissioner of the FDP in respect of the Karish-Tanin Development.

Energean Israel submitted its response on 14 January 2018 and the State Attorney submitted its response on 12 February 2018. The Supreme Court has set the hearing for the First Petition for 16 April 2018. The purpose of such hearing would be to determine whether a writ of certiorari should be granted in order to allow a hearing on

the merits of the First Petition. If the Supreme Court grants the writ of certiorari, then a hearing on the merits of the First Petition would normally be scheduled a few months after the grant of certiorari and then a decision would normally follow several months thereafter.

Second Petition

On 30 January 2018, Hof Hacarmel Regional Council (the "**Second Petitioner**" and, together with the First Petitioners, the "**Petitioners**"), a regional council adjacent to the Dor onshore facility, filed a petition (the "**Second Petition**") with the Israeli Supreme Court, against the Ministry of Energy, the Petroleum Commissioner, two Planning and Construction authorities, Energean Israel and an environmental union of local authorities for Sharon-Carmel, seeking annulment of the decision not to submit the development plan to the National Council for Planning and Construction (the "**National Council**") for approval and to annul the decision to allow Energean to construct "gas pipelines" planned to pass through the maritime "northern zone" of the National Outline Building and Zoning Plan 37/H.

The Second Petitioner also asked for an interim injunction to suspend any planning procedure and implementation by the respondents regarding Karish and Tanin until the petition is decided. On 15 February 2018, after all respondents filed their responses to the motion for interim injunction, the Supreme Court declined to grant such an injunction at this point. The Supreme Court has set the preliminary hearing for the Second Petition for 2 May 2018.

Possible outcomes of the Petitions

If, following any hearing on the merits of the Petitions, the Supreme Court were to rule in favour of the Petitioners, the court has considerable discretion with respect to the remedies it may grant. It is difficult to assess the likelihood and extent of any remedies that may be granted or imposed, the length of any delay that may be caused by the imposition of any such remedies (or as a consequence of the uncertainty that would accompany the continuation of litigation on these matters), the amount of any increased costs to the Group of implementing any such remedies or any other impacts on the Group's business. In respect of the First Petition, this is both because the First Petition is at a very early stage and because the issues raised have never to date been addressed by the Israeli courts.

If the Supreme Court chooses to grant the Petitioners the legal remedies they have requested, the approval of the FDP in respect of the Karish-Tanin Development could be revoked. In the case of the First Petition, the Group would need to follow the procedure described above for the re-approval of the FDP before it could proceed with any further development. In the case of the Second Petition, the Israeli Petroleum Commissioner would need to seek approval of the National Council, which, if modifications to the FDP were required, would require re-approving the FDP. Either such outcome could involve significant delay and increased costs, arising from any conditions which could be imposed by any such re-approval (to the extent that such conditions have not already been met) upon the development of the Karish and Tanin fields, and there can be no assurance such re-approval would be forthcoming on a timely basis or at all. Any significant delays beyond the long-stop dates determined in the Gas Supply Agreements could ultimately lead to termination of the Gas Supply Agreements.

Although the Directors believe, after due and careful enquiry, that it is unlikely that the outcome of either of the Petitions would have a material impact on the currently anticipated schedule and/or costs of the Karish-Tanin Development, there can be no assurance that the occurrence of any of the foregoing would not have a material adverse effect on the Group's ability to develop or commercialise the Karish-Tanin fields or more generally on the Group's business, results of operations, financial condition and/or prospects.

1.14 The Group's operations are subject to the risk of litigation, including risks relating to the criminal prosecution of the Group's officers and directors in the course of the conduct of their duties as part of the judicial system in Greece

From time to time, the Group may be subject to or otherwise impacted by litigation or arbitration arising out of its activities or operations, whether or not a direct party to those matters. Damages claimed, or the potential impact on the Group of the result under any such proceedings, may be material or may be indeterminate, and the outcome of such litigation or arbitration could materially and adversely affect the Group's reputation, business, results of operations, financial condition and/or prospects.

In addition, the directors of the Group's subsidiaries in Greece are exposed to increased risk of personal litigation in the Greek criminal courts as under Greek law any alleged offense resulting from the operations of those

subsidiaries will be attributed to their directors by virtue of them being their legal representatives against whom criminal charges may be brought. Moreover, the Directors believe that Greek prosecuting authorities often indict persons for more serious offences than initial investigation and evidence may appear to warrant, thereby leaving directors exposed to prolonged litigation until a court ultimately decides whether relevant offences have actually been committed or regarding the seriousness of any offences.

Currently, in the Group's operations at its subsidiary KOSA in Greece, certain directors of KOSA, including the Group's CEO Mathios Rigas, are involved in such criminal proceedings in Greece. In particular, Mr Evangelos Pappas (in his capacity as chairman and legal representative of KOSA during the period from July 2011 to 25 April 2013), Mr Emmanouil Kelaidakis (in his capacity as vice-chairman and legal representative of KOSA during the period from July 2011 to 25 April 2013), the Group CEO Mr Mathios Rigas (in his capacity as chairman and legal representative of KOSA during the period from 26 April 2013 onwards) and Mr Dimitrios Gontikas (in his capacity as vice-chairman/CEO and legal representative of KOSA during the period from 26 April 2013 onwards) were indicted under a charge of intentionally failing to prevent damage to property with respect to an underground gas supplying pipeline connecting to KOSA's onshore facilities, such damage having occurred due to the unearthing of the pipeline caused by long-term coastal erosion during the period from 2011 to 2015. At the hearing the court did not find intention and proceeded to a conviction for negligence, which carries a ten-month custodial sentence and is currently being appealed. In the event of an unsuccessful appeal, the sentence would be suspended due to its short term of under one year. Moreover, on 5 May 2017, Mr Dimitrios Gontikas, in his capacity as vice chairman/CEO of KOSA, was indicted for an alleged intentional improper disposal of hazardous waste, consisting of well cuttings from KOSA's drilling operation at Prinos in 2013. The trial is pending for 26 November 2018, and the vice chairman/CEO of KOSA intends to oppose the charge. In the event that the court finds according to the indictment, a custodial sentence is threatened of between one and five years and/or a fine of up to €60,000. If the court finds no intention but does find negligence or otherwise finds that the extent of any contamination was not material, a custodial sentence is threatened of up to one year and/or a fine. In all instances, any such custodial sentence is expected to be eligible for suspension.

The Group's CEO, Mr Mathios Rigas, in his capacity as chairman and CEO of EOGSA at the relevant time, has been served an indictment for an alleged 2015 offence of exercising of the rights of prospecting, exploration and exploitation of hydrocarbons without a licence and infringement of a provisional order relating to the suspension of such activities. The first hearing in the matter has now been set for 23 May 2018. See *"Additional Information—Alleged exploration of hydrocarbons without permission"*.

While the convictions and prosecution discussed above have not had a material adverse impact on the Group's business to date, any adverse publicity surrounding such claims or any similar claims in the future, or any liability that may result from any such similar claims against the Group or its employees in the future, could have a material adverse effect on the Group's business.

While the Group assesses the merits of each action and will consider defending it accordingly, the Group may be required to incur significant expenses in defending against litigation or arbitration and there can be no guarantee that a court or tribunal will find in the Group's favour. Further, the adverse publicity surrounding such claims could materially and adversely affect the Group's business, results of operations, financial condition and/or prospects.

For details on these and other proceedings, see Part 16 "*Additional Information—Litigation*".

1.15 The Group is leveraged and is subject to restrictive debt covenants and security arrangements that may limit its ability to finance its future operations and capital needs and to pursue business opportunities and activities. Breach of financial covenants may lead to default and/or liquidity risk

The Group has, and will continue to have, outstanding debt and debt service obligations. As of 31 October 2017, the Group's non-current borrowings were US$79.2 million, all of which was owed to third parties. The Group's interest bearing loans and interest bearing loans and borrowings expense for the ten month period ended 31 October 2017 was US$4.7 million (excluding amortisation of related parties' loan interest and issuance fees and other finance costs).

Under the terms of the RBL Senior Facility Agreement, the Group must comply with a number of covenants including financial maintenance covenants and restrictions on, among other matters, dividends and other distributions, cash movements, capital expenditure, additional future borrowings and indebtedness, and disposals and acquisitions. The breach of any of these covenants could constitute an event of default under the RBL Senior

Facility Agreement, in which case all amounts owed to the RBL Lenders would be due and payable immediately or upon demand by the RBL Lenders. For further information on the Group's debt covenants and security arrangements, see Part 16 "*Additional Information—Material Contracts*" and Part 11 "*Operating and Financial Review—Liquidity and Capital Resources—Capital Resources—Borrowings*". The Group may be subject to different and additional covenants or security arrangements from time to time as its financing arrangements change.

The covenants to which the Group is subject could limit its ability to finance discretionary business expansion and capital investment in the longer term, which in turn could have a material adverse effect on the Group's business, results of operations and financial condition. In addition, a substantial portion of the Group's assets in the Prinos basin, Greece, are fully pledged to the RBL Lenders. Such pledge may limit the Group's ability in the future to obtain financing or increase the cost such financing.

The Group's debt arrangements with the RBL Lenders involve a floating interest rate, consisting of a U.S. dollar LIBOR rate plus a fixed margin. To the extent the U.S. dollar LIBOR rate increases from current levels, the Group will be exposed to increased interest expenses. To the extent that service payments on its debt reduce the Group's cash flows available for capital investment or other business purposes, it may restrict the Group's ability to fund its operations, realise certain business opportunities or realise its business strategy.

To the extent the Group borrows or raises additional debt, the Group will be subject to increased interest expense, and may also be subject to additional covenants over and above those contained in the debt facilities that the Group maintains with the RBL Lenders and/or the Senior Credit Facility. In addition, future debt financings may limit the Group's ability to withstand financial pressures, as the Group may become illiquid or less liquid as a result of higher interest payments on its debt due to increases in interest rates or restrictions on cash movement. This could hinder the Group's ability to raise, renew and service its future indebtedness, reduce the funding options available to the Group and render it more vulnerable to economic downturns. In addition, if the Group requires debt but is unable to secure sufficient bank borrowings, it is highly likely that, other than in respect of its current committed capital expenditure, this would pose challenges to the Group's planned development and timeline for development.

Should the Group be unable to fund its operations through additional borrowings in the future, it may choose to pursue financing through the issuance of additional Shares and existing holders of Shares may suffer dilution in their percentage ownership or the market price of the Shares may be adversely affected.

1.16 The Group relies on the participation of its joint venture partner, Kerogen, in Energean Israel and must obtain Kerogen's consent to significant matters affecting Energean Israel's operations

Energean Israel, which holds the lease interests in the Karish and Tanin fields and the recently acquired Blocks 12, 21, 22, 23 and 31, is operated by the Group with its strategic partner Kerogen. Although the Group currently holds 50.0001% of the voting rights of Energean Israel, the existing shareholders' agreement governing the control and management of Energean Israel dated 13 June 2017 (the "**EISL Shareholders' Agreement**") specifies that the Group's strategy for the development and operation of the Karish and Tanin fields and the implementation of such strategy are subject to consulting with and obtaining the consent of Kerogen. As such, prior to the declaration of a final investment decision ("**FID**") the Group lacks the ability to control the development and operation of Karish and Tanin unilaterally. Following the declaration of FID and once the Group's interest in Energean Israel is increased to 70%, the scope of consents required from Kerogen in connection with the operation of Karish and Tanin will be reduced, and the Group will be able to approve the annual work plan and budget (within certain limits) without obtaining the consent of Kerogen. However, there can be no assurance that Kerogen will not disagree with the Group on certain strategic or operating decisions from time to time. Such opposition or delay may limit, delay or prevent the realisation of the Group's strategy with respect to its Israeli operations.

On 28 December 2017, Energean Israel, Energean E&P Holdings, the Founders and Kerogen entered into a subscription agreement based on commercial terms agreed in October 2017 (the "**Second EISL Subscription Agreement**"), pursuant to which Energean E&P Holdings agreed to subscribe for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash (including US$80 million which has been apportioned to carry the additional 20% interest in Energean Israel). Upon completion of such subscription, Energean E&P Holdings would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018 (or 30 June 2018 if Kerogen so consents).

The Group also depends on Kerogen to provide capital and other funding obligations provided for under the EISL Shareholders' Agreement. In particular, the Group anticipates that Kerogen will be required to provide equity financing for Phase 1 of the development of the Karish and Tanin fields as part of the total remaining equity funding commitment for Energean Israel of US$465.8 million (in addition to the US$60 million of equity which has already been funded). Kerogen's current share of such equity financing is approximately US$233 million, but this would be reduced to approximately US$60 million upon completion of the subscription for additional Energean Israel shares pursuant to the Second EISL Subscription Agreement, with the Group's equity financing commitment in Energean Israel increasing to approximately US$405 million. See also "*The Group's business strategy depends significantly on the successful development of the Karish and Tanin offshore gas fields in Israel, which are currently only at a very preliminary stage of development*". The Group does not control Kerogen and should Kerogen default on, delay in fulfilling or become unable to fulfil its obligations under the EISL Shareholders' Agreement or otherwise fail to arrange sufficient financing for the development of the Karish and Tanin fields, the Group may be unable to fund the operations in Israel, develop the Karish and Tanin fields successfully or otherwise realise the Group's strategy in Israel. Any such disagreement, delay, opposition, breach, or funding shortfall could adversely affect the Group's business, results of operations, financial condition and/or prospects.

1.17 The Group faces drilling, exploration and production risks and hazards that may affect its ability to produce oil and gas at expected levels, quality and costs

Oil and gas exploration and production operations are subject to certain risks including premature decline of reservoirs, invasion of water into producing formations, encountering unexpected formations or pressures, low permeability of reservoirs, blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations and abnormal geological pressures, uncontrollable flows of oil, gas or well fluids, build-up of asphaltene, gas hydrates or other precipitates, severe adverse weather or tidal conditions, natural disasters such as earthquakes, shortages of skilled labour or suppliers, access to utilities such as water, sabotage of or accidental damage to oil and gas pipelines, pollution and other environmental risks, any of which could materially adversely affect the Group's business, results of operations, financial condition and/or prospects.

Certain of the Group's facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, vessel collision, damage from anchors and damage from natural catastrophes or other severe adverse weather. The offshore drilling that the Group conducts could involve increased risks due to risks inherent in the nature of drilling in complex geological formations including blowouts, encountering unused or unexpected rock formations with abnormal geographical pressures and oil spills.

The occurrence of the above risks could result in environmental damage, including biodiversity loss or habitat destruction, injury to persons and loss of life, failure to produce oil in commercial quantities or an inability to fully produce discovered reserves. The risks mentioned above could also cause substantial damage to the Group's property and its reputation and put at risk some or all of its interests in its Leases which enable it to explore and/or produce, and could result in the Group incurring fines or penalties as well as criminal sanctions potentially being enforced against the Group and/or its officers with such fines, penalties or criminal sanctions potentially having a negative impact on the likelihood of the Group being awarded licences in the future. Consequent production delays and declines from normal field operating conditions and other adverse actions could have a material adverse impact on the Group's business, results of operations, financial condition and/or prospects.

1.18 The Group relies on technology systems, the failure of which could significantly impact its operations and business

The Group is reliant on its technology systems, in particular its specialist exploration applications. The Group's technology systems could be exposed to, amongst other things, damage or interruption from telecommunications failure, unauthorised entry and malicious computer code, fire, natural disaster, power loss, industrial action, human error and acts of war or terrorism. Recent international cyber-attacks have caused significantly detrimental consequences on the affected businesses. The occurrence of any of the above may also significantly disrupt the Group's technology systems and may lead to important data (such as the geophysical and geological data) being irretrievably lost or damaged, or to a significant interruption in normal operations. For example, a cyber-attack on the FPSO at the Karish-Tanin Development which compromises the supervisory control and data acquisition system of the FPSO could seriously damage the Group's operations in Israel. Such damage or interruption may adversely affect the Group's business, results of operations, financial condition and/or prospects.

1.19 Construction and operation of the FPSO present a number of logistical challenges for the Group

The FPSO which the Group intends to construct and operate at the Karish-Tanin Development represents a significant undertaking and poses a number of challenges for the Group. In particular, the Group will be dependent on the contractor TechnipFMC: the Group has entered into a cooperation agreement and EPCIC with TechnipFMC in respect of the Karish-Tanin Development; TechnipFMC has been the Group's contractor for work preceding the expected final investment decision with respect to the Karish and Tanin development (including front-end engineering and design) and the Group has entered into the approximately US$1.36 billion (multi-currency) Technip EPCIC Contract for the provision of the FPSO and all subsurface facilities.

The FPSO is expected to be constructed in Singapore and transported and set up near the Karish field in advance of final commissioning and commencement of gas production, but there can be no assurances that the transportation and hook-up with the manifold and pipeline near the field will occur on time or to expected specifications, which could be subject to additional delays and unexpected costs. Once operational, the FPSO will be subject to operational risks including severe weather, and at the time of its offshore commissioning, the FPSO is expected to be the only such floating assets in the Eastern Mediterranean, which potentially increases the likelihood of its being targeted in terrorist attacks, including physical attacks and cyber-attacks. In addition, because the FPSO is expected to operate for at least 30 years, expansion of capacity would generally have to be undertaken offshore, which carries significant cost and risk, and any need to move it for dry docking or maintenance which cannot be performed offshore would significantly disrupt the Group's operations and its ability to supply gas under the Gas Supply Agreements, any of which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.20 The Group depends on its Directors, key members of management, technical, exploration, financial and operational service providers and on its ability to retain and hire such persons to manage effectively its growing business

Attracting and retaining additional skilled personnel is fundamental to the successful growth of the Group's business. The Group requires skilled personnel in the areas of exploration and development, operations, engineering, business development, oil and gas marketing, finance, legal and accounting relating to its projects. Given the competitive market in which the Group operates, there can be no assurance that the Group will successfully attract new personnel or retain existing personnel required to continue to expand its business and to successfully execute and implement its business strategy. In particular, the Group may consider it appropriate or in certain cases be obliged by its local community relations programme or formal local content requirements to recruit local individuals. Given the relatively limited pool of individuals with the appropriate skills in certain countries in which the Group operates, there can be no guarantee that the Group can meet such aspirations or obligations and it may be required to recruit expatriate staff to fulfil such vacancies. The costs of recruiting appropriately skilled personnel may materially and adversely affect the Group's business, results of operations, financial condition and/or prospects.

1.21 A majority of the employees engaged by the Group are unionised, and wage demands or work stoppages by unionised employees could have an adverse effect on its business, results of operations, financial condition and/or prospects

The Group employs local workers, including contractors, in each of the countries in which it operates. Additionally, the contractors which the Group hires have their own employees from the regions in which the Group operates. A majority of the employees employed by the Group are represented by labour unions under collective bargaining agreements, including at the Group's operations in the Prinos basin where the majority of workers are members of the Kavala Workers' Association ("**KWA**"), which owns a 0.08% interest in the Group's subsidiary Kavala Oil S.A. ("**KOSA**"). These agreements need to be renewed from time to time and are currently agreed to the end of 2018. The Group or its contractors may not be able to negotiate acceptable new collective bargaining agreements or future restructuring agreements, which could result in labour disputes between the contractors and their employees. Work stoppages due to such disputes may lead to decreased productivity and/or revenue for the Group. Also, the Group may become subject to material cost increases or additional work rules imposed by agreements with labour unions through their relationships with local contractors. This could increase expenses in absolute terms and/or as a percentage of revenue. Additionally, material changes in the minimum wage, or other material changes to labour laws, in the countries in which the Group operates could have an effect on the Group's results. Although the Group believes it has good relations with its employees and contractors, work stoppages or other labour disturbances may occur in the future, which could have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.22 The Group may be subject to increased taxes, audits by tax authorities and liabilities in respect of historic tax periods, and the Group or certain of its employees or directors may be subject to civil or criminal liability for tax treatments arbitrarily imposed by Kavala Oil S.A.

The Group is subject to various forms of taxation and tax laws and regulations in the jurisdictions in which it operates. Accordingly, it is exposed to risks relating to increased taxation or changes in tax laws, to the risk of costs and loss of management time associated with tax audits, to the risk that it may rely on advice from tax advisors or guidance from tax authorities that could prove incorrect or to be subject to change and to the risk that it may discover that is has failed, or be found by tax authorities to have failed, in the past to pay the appropriate levels of tax or otherwise to comply with applicable tax laws and regulations, which could result in penalties and increased liabilities.

Effective for fiscal years ending 31 December 2011 onward, Greek companies meeting certain criteria have to be audited on an annual basis by their statutory auditor in respect of compliance with tax law. This audit leads to the issuance of a tax certificate which, under certain conditions, may reduce the likelihood of a full tax audit by the tax authorities; however, the tax authorities reserve the right to conduct a further tax audit. The Group company Energean Oil & Gas S.A. and its subsidiary KOSA have been audited by their respective statutory auditors and have received a tax compliance report with no findings, for fiscal years up to 2015 (inclusive).

However, there are a number of income tax years for which Group companies have not yet been audited. As a result, their income tax obligations are not considered final and there can be no assurance that the Group will not be subject to additional audits and additional tax liabilities and possible penalties.

During the year ended 31 December 2014, the statutory tax audit of KOSA for the years 2006 to 2011 was finalised and the official tax report was issued by the respective tax authorities. On 22 April 2015, KOSA proceeded in executing its mandatory administrative appeal before the Dispute Resolution Directorate of the Greek Ministry of Finance against certain tax assessment notices, for tax and transfer pricing penalties amounting to €5.6 million. The appeal primarily relates to the imposition by the Greek tax authorities of a transfer pricing-related fine of €5.3 million, calculated as 20% of an amount which the tax authorities contend is additional gross income received by KOSA in the 2010 and 2011 fiscal years (€15.6 million and €11.1 million of gross revenue, respectively) which KOSA should have recognised in respect of an intra-Group service fee. A prerequisite for the exercise of this appeal was the prepayment of 50% of the value of the amounts for which the appeal was executed and thus a total amount of €2.8 million was paid by KOSA during 2015. This amount was presented as advanced payment to Greek tax authorities. This appeal was rejected by the Dispute Resolution Directorate of the Greek Ministry of Finance. KOSA filed appeals before the Athens Administrative Court of Appeal against all of the decisions of the Dispute Resolution Directorate on 8 October 2015. The discussion of these actions took place in February 2017 and the final decision is expected in the first quarter of 2018. While the Group intends to maintain its position vigorously in the mandatory administrative appeal, success in the appeal cannot be assured, in which case, the Group would be liable for the remaining €2.8 million due, plus any accrued interest, payable within one month of the decision date. This has been recognised as a provision in the Consolidated Historical Financial Information (see note 19 in Section B of Part 13 *"Consolidated Historical Financial Information"*). For more details on the tax appeal, see Part 16 "*Additional Information—Litigation*".

In 2017, and in connection with the tax dispute, certain directors of KOSA (namely, the Group CEO Mr Mathios Rigas, in his capacity as chairman and legal representative of KOSA as of 23 August 2015, the date on which the assessed fines were originally due to be paid; Mr Evangelos Pappas, in his capacity as chairman and legal representative of KOSA during the audited financial years 2006 through 2011; Mr Emmanouil Kelaidakis, in his capacity as vice-chairman and legal representative of KOSA during the audited financial years 2006 through 2011; and Mr Dimitrios Gontikas, in his capacity as vice-chairman/CEO and legal representative of KOSA as of 23 August 2015) were indicted *ex officio* and by operation of law (without any need for fault to have been shown by the prosecuting authorities) and charged with failing to have paid the tax in respect of the tax authorities' findings discussed above, which constitutes a criminal offence for the directors under Greek tax law. The trial, scheduled for 4 April 2017, has been postponed to 25 April 2018. The outcome of this prosecution depends on and is associated with the outcome of KOSA's appeal described above, as the criminal offence is eliminated and punishment is not permitted if the amount assessed is fully paid prior to the trial hearing. As a result, the hearing of this criminal case against the KOSA board members will be requested to be postponed up and until the issuance of the pending decision in the appeal. Whether the decision in the appeal is in favour of KOSA or not, the KOSA directors intend to oppose the charge and in any event prosecution against the KOSA directors would cease if the remaining €2.8 million due (plus any accrued interest) is paid prior to any conviction. For more details on these prosecutions, see Part 16 "*Additional Information—Litigation*".

While the proceedings discussed above have not had a material adverse impact on the Group's business to date, any adverse publicity surrounding the claim or any similar claims in the future, or any liability that may result from any such similar claims in the future, could have a material adverse effect on the Group's business.

More generally, the Group cannot provide assurance that it will not be subject to further audits by tax authorities and possibly additional tax liabilities, including possibly civil or criminal liability, in Greece or other jurisdictions in which it operates.

1.23 The Group does not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions

The Group considers that the extent of its insurance cover is reasonable based on the costs of cover, the risks associated with its business and industry practice. The Group's insurance currently includes cover for its offshore facilities, onshore processing plant, operators' extra expense, physical loss or damage to its tender assisted drilling rig, primary and excess liabilities, support vessels protection and indemnity, support vessels hull and machinery, protection and indemnity for its tender assisted drilling rig and war risks for the rig and other vessels, in each case subject to deductibles, excesses, exclusions and limitations. There can be no assurance that such insurance will be adequate to cover any losses or exposure for liability or that the Group will continue to be able to obtain insurance to cover such risks. For example, the Group does not have business interruption insurance in place and, therefore, it cannot claim on any insurance policy to mitigate losses suffered as a result of shut-in or cessation in production.

The Group is unable to give any guarantee that expenses relating to losses or liabilities will be fully covered by the proceeds of applicable insurance. Consequently, the Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage. The Group is also subject to the future risk of unavailability of insurance, increased premiums or excesses, and expanded exclusions.

1.24 The Group is obliged to comply with health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations

The Group operates in an industry that is inherently hazardous and consequently subject to comprehensive regulation. Although the Group considers that it has adequate procedures in place to mitigate operational risks and keeps these under review, there can be no assurances that these will be adequate and failure to adequately mitigate risks may result in loss of life, injury, or adverse impacts on the health of employees, contractors or third parties or the environment. Failure, whether inadvertent or otherwise, by the Group to comply with applicable legal or regulatory requirements may give rise to significant liabilities and may result in loss of life, injury, or adverse impacts on the health of employees, contractors and third parties or the environment. The Group's health, safety and environment policy observes local and national, legal and regulatory requirements and generally applies best practices where local legislation does not exist or where environmental regulation does not presently occur.

The terms of licences or permissions may include more stringent environmental and/or health and safety requirements. Obtaining exploration, development or production licences and permits may become more difficult or be the subject of delay due to governmental, regional or local environmental consultation, approvals or other considerations or requirements.

The Group incurs, and expects to continue to incur, capital and operating costs in order to comply with health, safety and environmental laws and regulations. New laws and regulations, the imposition of tougher requirements in licences, increasingly strict enforcement or new interpretations of existing laws, regulations and licences, or the discovery of previously unknown contamination, may require further expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups;
- curtail or cease certain operations; or
- pay fees or fines or make other payments for pollution, discharges or other breaches of environmental requirements.

Although the costs of the measures taken to comply with environmental regulations have not had a material adverse effect on the Group's business, results of operations, financial condition and/or prospects to date, in the future, the costs of measures taken by the Group to comply with environmental regulations and liabilities related to environmental damage caused by the Group may increase, which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. In addition, it is not possible to predict what future environmental regulations will be enacted or how current or future environmental regulations will be applied or enforced. The Group may have to incur significant expenditure for the installation and operation of systems and equipment in the event that environmental regulations become more stringent or governmental authorities elect to enforce them more vigorously. Any such expenditure may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the cost of production, development or exploration activities.

In addition, the Group's operations are inherently subject to risks associated with natural catastrophes, fires, explosions, blowouts, encountering formations with abnormal pressure and crude oil spills, each of which could result in substantial damage to the Group's property and the surrounding environment or in personal injury, biodiversity loss or habitat destruction and result in liability and reputational damage to the Group. Should any of these risks and hazards materialise the consequences of such events could result in civil and/or criminal liability for the Group, and could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

Whilst the Group has contractual arrangements in place with its agents which seek to ensure its agents comply with all appropriate health and safety and environmental requirements, there can be no guarantee that the Group's agents adhere to such contractual arrangements or, if they do not adhere, that the Group will be made aware of any such breaches on a timely basis or at all. Furthermore, notwithstanding any contractual provisions stating otherwise, the Group may remain liable for the actions of its agents. In addition, there can be no guarantee that the steps being taken by any of the Group's agents will be appropriate and meet the relevant requirements. Accordingly, a failure by one of the Group's agents may have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.25 Climate change abatement legislation may have a material adverse effect on the Group's industry

Continued political attention to issues concerning climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on the Group. International agreements, national and regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted by particular countries. As such, climate change legislation and regulatory initiatives restricting emissions of greenhouse gases or promotion of, or consumer preference for, renewable energy sources such as solar may adversely affect the Group's operations, cost structure or the demand for oil and gas. Such legislation, regulatory initiatives or general consumer preference could have a material adverse effect by diminishing the demand for oil and gas, increasing the Group's cost structure or causing disruption to its operations by regulators. In addition, the Group may be subject to activism from groups campaigning against fossil fuel extraction, which could affect its reputation, disrupt its campaigns or programs or otherwise negatively impact the Group's business.

1.26 The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations

Licensees are typically obliged under the terms of relevant production sharing agreements or production agreements, licences or local law to dismantle and remove equipment, to cap or seal wells and generally to remediate production sites. In connection with the sale or transfer of the Group's assets, the Group may retain or be liable for decommissioning liabilities, even if it has not contractually agreed to accept these liabilities.

The Group's accounting policies require a provision to be made for the entire anticipated decommissioning costs of an asset when the related facilities are installed with the provision being subject to annual assessment and adjustment if required. The Group's financial statements for the period ended 31 October 2017 include a provision of US$3.9 million based on the Group's estimate of the aggregate decommissioning costs to be incurred following cessation of production by each of the Group's producing assets. These relate primarily to the wells which have been drilled in the Prinos basin since acquisition of the interest by the Group, as all

decommissioning in respect of legacy wells in the Prinos basin are the obligation of the Greek government upon termination of the Lease. Although the Group believes it has made adequate provision in respect of its anticipated decommissioning costs in the near to medium term, there can be no guarantee that the provision which has been made is sufficient. The Group's estimates are based on facts and circumstances known as of the date of such financial statements including the extent of the Group's operations. An increase in decommissioning costs could materially and adversely affect the Group's business, results of operations, financial condition and/or prospects. Additionally, these future decommissioning costs may require the posting of financial security, for example in the form of letters of credit. If the Group is unable to procure or renew such letters of credit on commercially acceptable terms or at all, it risks being in default of its licence obligations.

In addition, it is possible that the Group may incur decommissioning liabilities sooner than budgeted for, particularly if further declines in oil prices resulted in production from certain oil fields no longer being commercially viable, although the Directors do not anticipate that the Group will have any material decommissioning costs in the short to medium term. To the extent that the Group's costs in connection with decommissioning are higher than anticipated or are incurred earlier than anticipated, there could be a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

The costs of decommissioning may exceed the value of the long term provision set aside to cover such decommissioning costs. These costs may rise further as decommissioning activity in the oil and gas industry accelerates and competition for decommissioning equipment and services increases. The Group may have to draw on funds from other sources to fund such decommissioning costs.

1.27 For assets where the Group does not maintain the operatorship, its control over certain activities in respect of such assets will be limited

Certain of the Group's assets are operated through joint operating arrangements in which another party holds the majority interest, with the relationship between the parties governed by a joint operating agreement, as will be the case of the Group's joint operating agreement with Repsol in respect of Ioannina and Aitoloakarnania, where Repsol holds a 60% operating interest. For blocks 26 and 30 in Montenegro, the Lease obliges the Group to find two additional concessionaires to hold a participating interest in the Lease of at least 41% within 36 months of the signing of the lease (which occurred in March 2017). In the future, the Group could enter into further joint operating arrangements.

In such cases, the Group would be required to co-operate and agree with the operator in respect of the extent and timing of activities related to the acquired assets and the Group's ability to direct or control the activities of the operator will be limited to its participation in and by the powers given to the operating committee under the relevant joint operating agreement. Such arrangements could prevent the Group from developing the assets in the manner, or in the timeframe, it prefers and could result in reduction or delay in returns from the assets. Conversely, the Group may be required to fund development earlier than anticipated, or in amounts greater than expected, which may strain existing operations and could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

1.28 The Group is subject to foreign exchange and inflation risks, which might adversely affect its financial condition and results of operations

The Group's revenue and most of its working capital outside of Greece are in U.S. dollars. The Group does not currently engage in any foreign exchange hedging activity. The Group converts funds to foreign currencies as its payment obligations in jurisdictions where the U.S. dollar is not an accepted currency become due. Certain of the Group's costs are incurred in currencies other than U.S. dollars, including euros and pounds sterling. In particular a substantial portion of the Group's operating costs in Greece are in euros. Accordingly, the Group is subject to inflation in the countries in which it operates and fluctuations in the rates of currency exchange between the U.S. dollar and these currencies, and such fluctuations may materially affect the Group's business, results of operations, financial condition and/or prospects. Consequently, construction, exploration, development, administration and other costs may be higher than the Group anticipates.

2. Risks relating to the countries in which Energean operates

2.1 The geopolitical situation in Israel may adversely affect the Group's business

Because the Group has assets located in and offshore Israel, political, economic and military conditions in Israel may directly affect the Group's business. Israel has experienced and may be subject to future conflict and

violence in the region. The recent declaration by the United States that it recognises Jerusalem as the capital of Israel has increased tensions within Israel and surrounding countries, in particular Palestine. Popular uprisings in various countries in the Middle East and North Africa have affected the political stability of those countries, some of which are hostile to Israel. Any armed conflicts, terrorist activities or political instability involving Israel could disrupt the supply of electricity and natural gas in the Israeli market. The Group's development and/or future production operations with respect to the Karish-Tanin Development, although subject to security measures required by law and under the Lease requirements, could be specifically targeted by physical or cyber-attacks. Such attacks could impair the Group's ability to extract gas and deliver under its Gas Supply Agreements, which could adversely affect the Group's business, results of operations, financial condition and/or prospects.

Although the Israeli government currently covers the reinstatement value of direct damages that are caused by terrorist attacks or acts of war, the Group cannot assure prospective investors that this government coverage will be maintained or will be adequate in the event the Group submits a claim. Any security measures which the Group must undertake according to the law and under the Lease requirements, or which the Group decides it would be prudent to undertake, at its operations at the Karish-Tanin Development and/or the development of the five recently awarded blocks offshore Israel in the future could lead to unexpected additional costs or timing delays.

A number of countries, principally in the Middle East, still restrict doing business with Israel and companies with substantial operations in Israel, and additional countries may impose restrictions on doing business with Israel or companies with substantial operations in Israel if hostilities in Israel or political instability in the region continue or increase, which could restrict the ability of the Group to seek expansion or other business opportunities in certain countries. Any hostilities involving Israel or the interruption or curtailment of trade between Israel and its present trading partners, or significant downturn in the economic or financial condition of Israel, could adversely affect the Group's operations, cause its revenue to decrease and adversely affect its share price.

Any of these circumstances could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

2.2 The natural gas industry in Israel is under development and the Group will be dependent on government-owned and operated infrastructure to deliver its gas

The Israeli natural gas industry is still in the early stages of development with regard to the natural gas industry and the pipeline infrastructure currently offers limited redundancy for natural gas transmission. The Group will be dependent on government-owned and operated infrastructure to deliver its gas which still needs to be built. In particular, gas produced from the Karish and Tanin fields and processed via the FPSO will be delivered to the Group's customers by means of a pipeline approximately 90km long at the entry into the national transmission system operated by INGL. The last approximately 10km of the gas pipeline is to be constructed by Energean Israel and planned to be turned over for operation to INGL after installation and start-up of production from the FPSO.

Because the Group is limited in accordance with the terms of the Leases to selling gas it produces from the Karish and Tanin fields to the domestic Israeli market, to the extent that the anticipated development of the gas transmission infrastructure experiences delays in construction completion or any relevant component of the system is otherwise unavailable for whatever reason, such as malfunction or other disruption, the Group could be unable to supply the gas due under its Gas Supply Agreements, which could require the Group's customers to obtain their gas from other sources and could prevent the Group from entering into further arrangements for the supply of gas in Israel, which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects.

2.3 The Group's business in Greece may be exposed to the financial crisis in the country

The economic and business environment in Greece remains challenging. The Greek economy re-entered recession in 2015, following a mild recovery in 2014, mainly due to political and economic uncertainty. The implementation of capital controls on 28 June 2015 led to significant external liquidity shortages and the need for implementing new fiscal adjustment measures following the agreement on a new programme for financial support in August 2015.

There can be no assurance that these measures will achieve the stabilisation of the Greek economy, or that Greece will be able to repay its sovereign debt.

The Group's business, operating results and financial condition are affected to a large extent by political developments in Greece. The current political, economic and budgetary challenges that the Greek government faces with respect to Greece's high public debt burden and weakening economic prospects may continue throughout 2017 and beyond, which could contribute to political and economic instability.

As a result of the economic environment in Greece, Greek commercial banks have a severely limited ability to extend finance generally, although this has had limited impact on the Group, which has sought funding from international lenders.

The Greek economy remains susceptible to risks associated with the ability of the government to access international markets and to attract funding at affordable interest rates. Although the Group is not directly exposed to the Greek economy as its entire current oil production from Greece is sold internationally to BP, the Group's business and financial condition could be affected by changes in Greek government policy, taxation, environmental regulation and other political or social developments affecting Greece.

2.4 The Group is exposed to the risk of adverse sovereign action by governments and any uncertainty around the application of local laws in the countries in which it operates

In certain countries, oil and gas companies have faced the risks of expropriation or renationalisation, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks. While the Group does not anticipate any adverse actions, it can offer no assurance that it will not be subject to any of the above risks in the countries in which it operates.

Possible future changes in the government, major policy shifts or increased security arrangements could have adverse effects on the value of investments. These factors could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

3. Risks relating to the Global Offer and the Shares

3.1 The Major Shareholders will retain a significant interest in and will continue to exert substantial influence over the Group following the Global Offer and their interests may differ from or conflict with those of other shareholders

Immediately following Admission, Third Point, Growthy Holdings, Oilco Investments and Adobelero (Growthy Holdings, Oilco Investments and Adobelero together the "**Founders**") as Major Shareholders will continue to beneficially own, in aggregate, approximately 54% of the issued ordinary share capital of the Company. The Founders, who collectively are interested in approximately 27% of the issued share capital of the Company, are deemed to be acting in concert with each other for the purposes of the City Code. Each of Third Point, Growthy Holdings and Oilco Investments have entered into relationship agreements which will, conditional upon Admission, regulate (in part) the degree of control that such shareholder and its affiliates may exercise over the management of the Company. The relevant relationship agreement also permits each of these shareholders to appoint one director to the Board for so long as such shareholder and its affiliates hold not less than 10% of the issued Shares. As a result, in addition to their respective rights under the relevant Relationship Agreement to appoint a director to the Board, the Major Shareholders will possess sufficient voting power to have a significant influence over all matters requiring shareholder approval, including the election of directors, dividend policy, remuneration policy and approval of significant corporate transactions. As of the date of this Prospectus, interests of the Founders and Third Point may not be aligned with each other or those of other holders of Shares.

3.2 The market price of the Shares could be negatively affected by sales of substantial amounts of such Shares in the public markets, including following the expiry of the lock-up period, or the perception that these sales could occur

Following completion of the Global Offer, the Major Shareholders will own beneficially, in aggregate, 52% of the Company's issued ordinary share capital. The Company, the Major Shareholders, the Directors and certain members of the Company's management team are subject to restrictions on the issue, sale and/or transfer, as applicable, of their respective holdings in the Company's issued share capital as described in Part 15 "*Details of the Global Offer—Lock up arrangements*". The issue or sale of a substantial number of Shares by the Company, the Major Shareholders, the Directors or certain members of the Company's management team in the public

market after the lock up restrictions in the Underwriting Agreement and related arrangements expire (or are waived by the Joint Global Co-ordinators), or the perception that these sales may occur, may depress the market price of the Shares and could impair the Company's ability to raise capital through the sale of additional equity securities.

3.3 There is no existing public market for the Shares and market demand for the Shares may not develop or be sustained

Prior to Admission, there has been no public trading market for the Shares. Although the Company has applied to the UK Listing Authority for admission to the premium listing segment of the Official List and has applied to the London Stock Exchange for admission to trading on its main market for listed securities, the Company can give no assurance that market demand for the Shares will develop or, if developed, could be sustained following the closing of the Global Offer. If market demand is not developed or maintained, the liquidity and trading price of the Shares could be adversely affected.

3.4 Shares in the Company may be subject to market price volatility and the market price of the Shares in the Company may decline disproportionately in response to developments that are unrelated to the Group's operating performance

The Offer Price is not indicative of the market price of the Shares following Admission. The market price of the Shares may be volatile and subject to wide fluctuations. The market price of the Shares may fluctuate as a result of a variety of factors, including, but not limited to, those referred to in these Risk Factors, as well as period to period variations in operating results or changes in revenue or profit estimates by the Group, industry participants or financial analysts. Shareholders may experience fluctuations in the market price of the Shares as a result of, amongst other factors, movements in the exchange rate between pounds sterling, the euro and the U.S. dollar.

The market price could also be adversely affected by developments unrelated to the Group's operating performance, such as the operating and share price performance of other companies that investors may consider comparable to the Group, speculation about the Group in the press or the investment community, unfavourable press, strategic actions by competitors (including acquisitions and restructurings), changes in market conditions, particularly the oil price, regulatory changes, a change in the UK political environment (particularly with regard to "Brexit" negotiations) and investor appetite for, or views with regard to, listed equity. In particular, since the United Kingdom's referendum in June 2016 to leave the European Union, the pound sterling to U.S. dollar exchange rate has decreased significantly and remains subject to significant fluctuations and uncertainty, particularly in light of the 2017 general election results in the United Kingdom and continued lack of clarity regarding the terms of its exit from the European Union.

The Group reports its results of operations and financial condition in U.S. dollars while the Company's share price will be quoted on the London Stock Exchange in pounds sterling. As a consequence, Any or all of these factors could result in material fluctuations in the price of Shares, which could lead to investors getting back less than they invested or a total loss of their investment.

3.5 Shareholders in the United States and other jurisdictions may not be able to participate in future equity offerings

The Articles provide for pre-emption rights to be granted to shareholders in the Company, unless such rights are dis-applied by a shareholder resolution. However, securities laws of certain jurisdictions may restrict the Group's ability to allow participation by shareholders in future offerings. In particular, shareholders in the United States may not be entitled to exercise these rights, unless either the Shares and any other securities that are offered and sold are registered under the U.S. Securities Act, or the Shares and such other securities are offered pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. The Company cannot assure prospective investors that any exemption from such overseas securities law requirements would be available to enable U.S. or other shareholders to exercise their pre-emption rights or, if available, that the Company will utilise any such exemption.

3.6 The Company's ability to pay dividends in the future depends, among other things, on the Group's financial performance and capital requirements and is therefore not guaranteed

There can be no guarantee that the Group's historic performance will be repeated in the future, particularly given the competitive nature of the industry in which it operates, and its sales, profit and cash flow may significantly

underperform market expectations. If the Group's cash flow deteriorates, then the Company's capacity to pay a dividend will suffer. Any decision to declare and pay dividends will be made at the discretion of the Directors and will depend on, among other things, applicable law, regulation, restrictions, the Group's financial position (including the existence of sufficient distributable reserves and cash in the Group), working capital requirements, finance costs, general economic conditions and other factors the Directors deem significant from time to time.

3.7 The issuance of additional Shares in the Company in connection with future acquisitions or other growth opportunities, any share incentive or share option plan or otherwise may dilute all other shareholdings

The Group may seek to raise financing to fund future acquisitions and other growth opportunities. The Group may, for these and other purposes, issue additional equity or convertible equity securities. As a result, existing holders of Shares may suffer dilution in their percentage ownership or the market price of the Shares may be adversely affected.

3.8 The Company is a holding company with no business operations of its own and depends on its subsidiaries for cash, including in order to pay dividends

The Company is a group holding company with no independent operations and is dependent on earnings and distributions of funds from its operating subsidiaries for cash, including in order to pay dividends to Shareholders.

As a matter of English law, the Company can pay dividends only to the extent that it has sufficient distributable reserves available, which depends upon the Company receiving cash from its operating subsidiaries in a manner which creates distributable reserves. The Company's ability to pay dividends to Shareholders therefore depends on its future Group profitability, the ability to distribute or dividend profits from its operating subsidiaries up the Group structure to the Company, general economic conditions and other factors the Directors deem significant. The Group's distributable reserves can be affected by reductions in profitability as well as by impairment of assets.

3.9 Overseas shareholders may be subject to exchange rate risk

The Shares are, and any dividends to be paid in respect of them will be, denominated in pounds sterling. An investment in Shares by an investor whose principal currency is not pounds sterling exposes the investor to foreign currency exchange rate risk. Any depreciation of pounds sterling in relation to such foreign currency will reduce the value of the investment in the Shares or any dividends in foreign currency terms.

3.10 U.S. investors may suffer adverse tax consequences if the Company is characterized as a passive foreign investment company ("PFIC")

Based on the Company's historic and expected operations, composition of assets, expected market capitalisation (which will fluctuate from time to time) and giving effect to the proceeds of the Global Offer, the Company does not expect that it will be classified as a PFIC for the current taxable year or for the foreseeable future. However, the determination of whether the Company is a PFIC is made annually, after the close of the relevant taxable year and depends on a number of factors, including the value of a corporation's assets and the amount and type of its gross income. Further, because the value of the Company's gross assets is likely to be determined in large part by reference to its market capitalisation, a decline in the value of the Company's ordinary shares may result in its becoming a PFIC. Therefore, it is possible that the Company could be classified as a PFIC for the current taxable year or in future years due to changes in composition of its assets or income, as well as changes in its market capitalization. If the Company is a PFIC for any taxable year during which a U.S. Holder (as defined in Part 16 "*Additional Information—Certain U.S. Federal Income Tax Considerations*") holds Shares, certain adverse U.S. federal income tax consequences could apply to such U.S. Holder. See *"Additional Information—Certain U.S. Federal Income Tax Considerations—Passive foreign investment company rules."*

PART 2
IMPORTANT INFORMATION

General

Investors should only rely on the information in this Prospectus. No person has been authorised to give any information or to make any representations in connection with the Global Offer, other than those contained in this Prospectus and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors, the Major Shareholders or the Banks. No representation or warranty, express or implied, is made by any of the Banks or any selling agent as to the accuracy or completeness of such information, and nothing contained in this Prospectus is, or shall be relied upon as, a promise or representation by any of the Banks or any selling agent as to the past, present or future. Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to the FSMA, neither the delivery of this Prospectus nor any subscription or sale of Shares pursuant to the Global Offer shall, under any circumstances, create any implication that there has been no change in the business or affairs of the Group since the date of this Prospectus or that the information contained herein is correct as of any time subsequent to its date.

The Company will update the information provided in this Prospectus by means of a supplementary Prospectus if a significant new factor that may affect the evaluation by prospective investors of the Global Offer occurs after the publication of the Prospectus or if this Prospectus contains any mistake or substantial inaccuracy. The Prospectus and any supplementary Prospectus thereto will be subject to approval by the FCA and will be made public in accordance with the Prospectus Rules. If a supplement to the Prospectus is published prior to Admission, investors shall have the right to withdraw their applications for Shares made prior to the publication of the supplement. Such withdrawal must be made within the time limits and in the manner set out in any such supplement (which shall not be shorter than two clear business days after publication of the supplement).

The contents of this Prospectus are not to be construed as legal, business or tax advice. Each prospective investor should consult his or her own lawyer, financial adviser or tax adviser for legal, financial or tax advice. Each prospective investor should consult with such advisers as needed to make its investment decision and to determine whether it is legally permitted to hold shares under applicable legal investment or similar laws or regulations. None of the Company, the Directors, the Major Shareholders or any of the Banks or any of their representatives is making any representation to any offeree, subscriber or purchaser of the Shares regarding the legality of an investment by such offeree, subscriber or purchaser. In making an investment decision, each investor must rely on their own examination, analysis and enquiry of the Company and the terms of the Global Offer, including the merits and risks involved.

This Prospectus is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation by any of the Company, the Directors, the Major Shareholders, any of the Banks or any of their representatives that any recipient of this Prospectus should subscribe for or purchase the Shares. Prior to making any decision as to whether to subscribe for or purchase the Shares, prospective investors should read this Prospectus. Prospective investors should ensure that they read the whole of this Prospectus carefully and not just rely on key information or information summarised within it, in particular, prospective investors should pay specific attention to the section entitled "*Risk Factors*".

Investors who subscribe for or purchase Shares in the Global Offer will be deemed to have acknowledged that: (i) they have not relied on any of the Banks or any person affiliated with any of them in connection with any investigation of the accuracy of any information contained in this Prospectus or their investment decision; and (ii) they have relied on the information contained in this Prospectus, and no person has been authorised to give any information or to make any representation concerning the Group or the Shares (other than as contained in this Prospectus) and, if given or made, any such other information or representation should not be relied upon as having been authorised by the Company, the Directors, the Major Shareholders or any of the Banks.

In connection with the Global Offer, the Managers and any of their respective affiliates, acting as investors for their own accounts, may subscribe for and / or acquire Shares and in that capacity may retain, purchase, sell, offer to sell or otherwise deal for their own accounts in such Shares and other securities of the Company or related investments in connection with the Global Offer or otherwise. Accordingly, references in this Prospectus to the Shares being issued, offered, subscribed, acquired, placed or otherwise dealt in should be read as including any issue, offer, subscription, acquisition, dealing or placing by, the Managers and any of their affiliates acting as investors for their own accounts. None of the Managers intends to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligations to do so.

Presentation of financial information

The consolidated historical financial information of the Group as of and for the ten months ended 31 October 2017 and as of December 31, 2016, 2015 and 2014 for the years then ended ("**Consolidated Historical Financial Information**") in this Prospectus has been prepared in accordance with International Financial Reporting Standards as adopted by the European Union ("**IFRS**"), except as noted in note 2 to the Consolidated Historical Financial Information, "Basis of Preparation". The significant IFRS accounting policies applied in the financial information of the Company are applied consistently for all periods in the financial information in this Prospectus.

Financial information

The Company's financial year runs from 1 January to 31 December. The financial information included in Section B of Part 13 "*Consolidated Historical Financial Information*" is covered by the accountant's report included in Section A, which was prepared in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom.

None of the financial information used in this Prospectus has been audited in accordance with auditing standards generally accepted in the United States of America ("**U.S. GAAS**") or auditing standards of the Public Company Accounting Oversight Board (United States) ("**PCAOB**"). Accordingly, it would not be possible to express any opinion on the Consolidated Historical Financial Information in Section B of Part 13 "*Consolidated Historical Financial Information*" under U.S. GAAS or the auditing standards of the PCAOB. In addition, there could be other differences between the auditing standards issued by the Auditing Practices Board in the United Kingdom and those required by U.S. GAAS or the auditing standards of the PCAOB. Potential investors should consult their own professional advisers to gain an understanding of the Consolidated Historical Financial Information in Section B of Part 13 "*Consolidated Historical Financial Information*" and the implications of differences between the auditing standards noted herein.

Non-IFRS financial information

This Prospectus contains certain financial measures that are not defined or recognised under IFRS, in particular, Adjusted EBITDAX, Free Cash Flow, Cost of Oil Production, Cost of Oil Production per boe, Net Debt and Gearing Ratio (Net Debt to Capital), each of which is defined below. The Directors believe that each of these measures provides useful information with respect to the performance of the Group's business and operations.

These non-IFRS financial measures and other metrics are unaudited and are not measures recognised under IFRS or any other internationally accepted accounting principles, and prospective investors should not consider such measures as an alternative to the IFRS measures included in the Group's Consolidated Historical Financial Information. Even though the non-IFRS financial measures and other metrics are used by management to assess the Group's financial results and these types of measures are commonly used by investors, they have important limitations as analytical tools, and investors should not consider them in isolation or as substitutes for analysis of the Group's position or results as reported under IFRS.

An explanation of the relevance of each of the non-IFRS measures to the most directly comparable measures calculated and presented in accordance with IFRS and a discussion of their limitations is set out below.

Adjusted EBITDAX

Adjusted EBITDAX is a non-IFRS financial measure that is calculated by the Group as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange gain / (loss) and exploration and evaluation expenses.

Adjusted EBITDAX presented by the Group has been calculated based on information derived from the Consolidated Historical Financial Information and other relevant information contained in Section B of Part 13 "*Consolidated Historical Financial Information*." The Group presents Adjusted EBITDAX as it is used in assessing the Group's growth and operational efficiencies as it illustrates the underlying performance of the Group's business by excluding items considered by management not to be reflective of the underlying operations of the Group. Information regarding Adjusted EBITDAX or similar measures is sometimes used by investors to evaluate the efficiency of a company's operations and its ability to employ its earnings toward repayment of debt, capital expenditure and working capital requirements.

Adjusted EBITDAX has limitations as an analytical tool and should not be considered in isolation or as a substitute for analysis of the Group's results as reported under IFRS. Adjusted EBITDAX should not be used as an alternative to net income (loss), operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with IFRS. The Group's presentation of Adjusted EBITDAX may not be comparable to similarly titled measures used by other companies in the Group's industry. Furthermore, presentation of Adjusted EBITDAX should not be construed as an inference that the Group's future results will be unaffected by the items noted above or what the Group believes to be other unusual items, or that in the future the Group may not incur expenses that are the same as or similar to some of the adjustments in this presentation.

For a quantitative reconciliation of the Group's Adjusted EBITDAX to profit / (loss) for the period, see Part 10 "*Selected Financial Information—Key Performance Indicators.*"

Free Cash Flow

Free cash flow is a non-IFRS measure that is defined by the Group as net cash from / (used in) operating activities less payment for purchase of intangible assets and payment for purchase of property, plant and equipment. Free cash flow presented by the Group has been calculated based on information derived from the Consolidated Historical Financial Information and other relevant information contained in Section B of Part 13 "*Consolidated Historical Financial Information*." Free cash flow is a liquidity measure used as an indicator of the Group's ability to make strategic investments, repay its debt and meet other payment obligations. Information regarding free cash flow or similar measures is sometimes used by investors to enhance understanding of cash generation and as a supplemental measure for comparing liquidity in respect of operations from period to period without the distortions of capital expenditures.

Free cash flow does not reflect any restrictions on the transfer of cash and cash equivalents within the Group or any requirement to repay the Group's borrowings and does not take into account cash flows that are available from disposals or the issue of shares. Management therefore takes such factors into account in addition to free cash flow when determining the resources available for acquisitions and distributions to shareholders.

For a quantitative reconciliation of free cash flow to net cash from / used in operating activities, see Part 10 *"Selected Financial Information—Key Performance Indicators."*

Cost of Oil Production and Cost of Oil Production per boe

Cost of oil production is a non-IFRS measure that is defined as cost of oil sales, less cost of services, depreciation and change in inventory (defined as the difference between opening inventory and closing inventory). Cost of oil production per boe represents cost of oil production divided by total production for the respective period.

Cost of oil production and cost of oil production per boe presented by the Group have been calculated based on information derived from the Consolidated Historical Financial Information and other relevant information contained in Section B of Part 13 "*Consolidated Historical Financial Information*." The Group presents cost of oil production and cost of oil production per boe because the Group believes they provide a measure for comparing the Group's operational performance against that of its peer group. In addition, the Group uses these measurements to compare the performance of the Group's operations period-to-period, to monitor costs and to evaluate operating efficiency. Cost of oil production should not be considered in isolation or as an alternative to operating expenses or cost of sales. Although the presentation of cost of oil production and cost of oil production per boe is common industry practice, the Group's calculations of these items may vary from other oil and gas companies' calculations, and by themselves do not necessarily provide a basis for comparison with other oil and gas companies.

Cost of oil production has important limitations as an analytical tool. Cost of oil production does not reflect the impact of depreciation on assets of the Group nor does it reflect the change in inventory for the respective period. Further, cost of oil production does not reflect the complete cost of oil production and additional costs necessary to sustain the output of the Group, which includes selling and distribution expenses and administrative expenses.

For a quantitative reconciliation of cost of oil production to cost of sales and for the calculation of cost of oil production per boe, see Part 10 *"Selected Financial Information—Key Performance Indicators."*

Net Debt

Net debt is a non-IFRS measure that is defined as the Group's total borrowings (including current and non-current borrowings) less shareholders' subordinated debt, cash and cash equivalents and bank deposits. Net debt presented by the Group has been calculated based on information derived from the Consolidated Historical Financial Information and other relevant information contained in Section B of Part 13 "*Consolidated Historical Financial Information*."

Management believes that net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding borrowings. Management believes that net debt can assist securities analysts, investors and other parties to evaluate the Group. Net debt and similar measures are used by different companies for differing purposes and are often calculated in ways that reflect the circumstances of those companies. Accordingly, caution is required in comparing net debt as reported by the Group to net debt of other companies.

For a quantitative reconciliation of net debt to total borrowings, see Part 10 "*Selected Financial Information—Key Performance Indicators."*

Gearing Ratio (Net Debt to Capital)

The Group defines capital as the Group's total equity plus shareholders' subordinated debt. The Group calculates the gearing ratio (net debt to capital) as net debt divided by capital. Management believes that the net debt to capital ratio is a useful ratio to measure how the Group finances its operations. Management believes that the net debt to capital ratio is a useful ratio to assist securities analysts, investors and other parties in evaluating the Group's financial structure and how the Group is financing its operations, along with insight into the Group's financial strength. Net debt to capital ratio is used by different companies for differing purposes and are often calculated in ways that reflect the circumstances of those companies. Accordingly, caution is required in comparing the net debt to capital ratio by the Group to the net debt to capital ratio of other companies.

For the calculation of the gearing ratio (net debt to capital), see Part 10 "*Selected Financial Information—Key Performance Indicators."*

The non-IFRS financial measures and other metrics, each as defined herein, may not be comparable to similarly titled measures presented by other companies as there are no generally accepted principles governing the calculation of these measures and the criteria upon which these measures are based can vary from company to company.

Unaudited financial measures and other metrics in relation to the Group have been derived from (i) management accounts for the relevant accounting periods presented; (ii) internal financial reporting systems supporting the preparation of the Group's Consolidated Historical Financial Information contained in Section B of Part 13 "*Consolidated Historical Financial Information*"; and (iii) the Group's other business operating systems and records. Management accounts are prepared using information derived from accounting records used in the preparation of the Group's Consolidated Historical Financial Information contained in Section B of Part 13 "*Consolidated Historical Financial Information*" but may also include certain other assumptions and analyses.

Reserve and resource reporting

Unless otherwise indicated, the NSAI CPRs contained in Part 19: "*Competent Persons' Reports*" in this Prospectus have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System ("**PRMS**") approved by the Society of Petroleum Engineers ("**SPE**").

As set out in the NSAI CPRs, "**contingent resources**" are defined by NSAI as those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies.

Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

For contingent resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C, respectively.

Approximately 92% of the resources covered by the NSAI Israeli CPR are contingent only upon project sanctioning and the availability of project financing. The financing for Phase 1 of the Karish-Tanin Development, principally comprising the Senior Credit Facility and a portion of the proceeds of the Global Offer, will be in place as of the date of Admission. The project sanctioning condition will be satisfied at the point that the Group proceeds with the final investment decision, which is in the control of the Group and is expected to take place within 30 days following Admission. The Directors believe that, on satisfaction of the above two contingencies, these contingent resources will satisfy the criteria to be classified as reserves. The Group intends to commission an update of the NSAI Israeli CPR as of 30 June 2018, by which point the two contingencies above are anticipated to have been satisfied and these contingent resources would be re-classified as reserves.

In addition, the contingent resources in the Karish Field B Sand (which represent the remaining approximately 8% of the contigent resources covered by the NSAI Israeli CPR) are further contingent upon sufficient flow testing to establish commercial productivity. The costs required to resolve these contingencies have not been included in the NSAI Israeli CPR and the estimates of cash flow included therein are based on the assumption that all contingencies will be successfully addressed.

As set out in the NSAI CPRs, "**prospective resources**" are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in the NSAI CPRs should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made.

Totals of unrisked prospective resources beyond the reservoir level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each reservoir, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Prospective investors should not place undue reliance on the forward-looking statements in the NSAI CPRS or on the ability of NSAI to predict actual reserves or resources. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. Prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. Prospective resources may not result in the successful discovery of economic resources in which case there would be no commercial development.

The information on resources in this Prospectus and in the NSAI CPRs is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the NSAI CPRs is set out in more detail in each report.

Currency presentation

Unless otherwise indicated, references to "dollars", "U.S. dollars", "US$" or "cents" are to the lawful currency of the United States. The Group has prepared the Consolidated Historical Financial Information in U.S. dollars. References to "sterling", "pounds sterling", "GBP", "£", or "pence" are to the lawful currency of the United Kingdom. References to "euros" or "€" are to the official currency of the Eurozone.

The following tables set out, for the periods set forth below, the high, low, average and period-end Bloomberg Composite Rates for the euro and the pound sterling expressed as U.S. dollars per £1.00 and U.S. dollars per €1.00 respectively. The Bloomberg Composite Rate is a "best market" calculation, in which, at any point in time, the composite bid rate is equal to the highest bid rate of all currently active, contributed, bank indications, and the composite ask rate is equal to the lowest ask rate offered by these same bank indications. The Bloomberg Composite Rate is a mid-value rate between the composite bid rate and the composite ask rate. The rates may differ from the actual rates used in the preparation of the Consolidated Historical Financial Information and other financial information appearing in this Prospectus. Where an amount is expressed in sterling and a comparative U.S. dollar amount is provided for reference, such U.S. dollar amount has been calculated at an exchange rate of US$1.3927 = £1.00.

The average rate for a year, a month, or for any shorter period, means the average of the daily Bloomberg Composite Rates during that year, month, or shorter period, as the case may be.

Period (Year/Month)	Period end	Average	High	Low
		(U.S. dollar per £1.00)		
2015	1.4734	1.5283	1.5883	1.4632
2016	1.2340	1.3553	1.4810	1.2158
2017	1.3513	1.2884	1.3594	1.2068
January 2018	1.4184	1.3814	1.4256	1.3513
February 2018	1.3785	1.3963	1.4230	1.3785
March 2018 (through 14 March)	1.3974	1.3866	1.3974	1.3735

Source: Bloomberg

Period (Year/Month)	Period end	Average	High	Low
		(U.S. dollar per €1.00)		
2015	1.0866	1.1100	1.2099	1.0496
2016	1.0517	1.1068	1.1527	1.0384
2017	1.2005	1.1295	1.2036	1.0427
January 2018	1.2415	1.2196	1.2492	1.1921
February 2018	1.2209	1.2347	1.2478	1.2209
March 2018 (through 14 March)	1.2375	1.2338	1.2400	1.2212

Source: Bloomberg

Roundings

Certain data in this Prospectus, including financial, statistical, and operating information has been rounded. As a result of the rounding, the totals of data presented in this Prospectus may vary slightly from the actual arithmetic totals of such data. Percentages in tables have been rounded and accordingly may not add up to 100%.

Market, economic and industry data

Unless the source is otherwise stated, the market, economic and industry data in this Prospectus constitute the Directors' estimates, using underlying data from independent third parties. The Company obtained market data and certain industry forecasts used in this Prospectus from internal surveys, reports and studies, where appropriate, as well as market research, publicly available information and industry publications.

The Company confirms that all such data contained in this Prospectus has been accurately reproduced and, so far as the Company is aware and able to ascertain, no facts have been omitted that would render the reproduced information inaccurate or misleading.

Where third party information has been used in this Prospectus, the source of such information has been identified.

Service of process and enforcement of civil liabilities

The Company has been incorporated under English law. Service of process upon Directors and officers of the Company may be difficult to obtain within the United States or other jurisdictions in which investors may be located. Furthermore, since most directly owned assets of the Company are outside the United States, and may be outside other jurisdictions in which investors may be located, any judgment obtained in the United States or such other jurisdictions against the Company may not be collectible within the United States or such other jurisdictions. In addition, current Israeli law is not clear-cut on the application of specific local laws to activities or assets located outside of Israel's Territorial Waters (outside an area of 12 nautical miles from shore), in an area defined by international law as Israel's Continental Shelf and Exclusive Economic Zone. Recently, the Israeli government has been working on legislation to eradicate the uncertainty surrounding application of domestic laws in the EEZ. See also Part 7 "*Regulatory Overview—Regulatory and legislative framework in Israel—Government Regulations—The Marine Bill*".

There is doubt as to the enforceability of certain civil liabilities under U.S. federal securities laws (and there may be doubt as to the enforceability of liabilities under the laws of other jurisdictions in which investors may be

located) in original actions in English courts (and in the courts of other jurisdictions in which investors may be located). Subject to certain exceptions and time limitations, English courts will treat a final and conclusive judgment of a U.S. court for a liquidated amount as a debt enforceable by fresh proceedings in the English courts.

No incorporation of website information

The contents of the Company's website do not form part of this Prospectus.

Definitions and glossary

Certain terms used in this Prospectus, including all capitalised terms and certain technical and other items, are defined and explained in Part 17 "*Definitions*" and Part 18 "*Glossary of Technical Terms*".

Information not contained in this Prospectus

No person has been authorised to give any information or make any representation other than those contained in this Prospectus and, if given or made, such information or representation must not be relied upon as having been so authorised. Neither the delivery of this Prospectus nor any subscription or sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this Prospectus or that the information in this Prospectus is correct as of any time subsequent to the date hereof.

Information regarding forward-looking statements

This Prospectus includes forward-looking statements. These forward-looking statements involve known and unknown risks and uncertainties, many of which are beyond the Group's control and all of which are based on the Directors' current beliefs and expectations about future events. Forward-looking statements are sometimes identified by the use of forward-looking terminology such as "believe", "expects", "may", "will", "could", "should", "shall", "risk", "intends", "estimates", "aims", "plans", "predicts", "continues", "assumes", "positioned" or "anticipates" or the negative thereof, other variations thereon or comparable terminology. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout this Prospectus and include statements regarding the intentions, beliefs or current expectations of the Directors or the Group concerning, among other things, the results of operations, financial condition, prospects, growth, strategies, and dividend policy of the Group and the industry in which it operates. In particular, the statements under the headings "*Summary*", "*Risk Factors*", "*Business Overview*" and "*Operating and Financial Review*" regarding the Group's strategy and other future events or prospects are forward-looking statements.

These forward-looking statements and other statements contained in this Prospectus regarding matters that are not historical facts involve predictions. No assurance can be given that such future results will be achieved; actual events or results may differ materially as a result of risks and uncertainties facing the Group. Such risks, uncertainties and other important factors include, but are not limited to, those listed under the heading "*Risk Factors*".

The following include some but not all of the factors that could cause actual results or events to differ materially from the anticipated results or events:

- failure to successfully develop the Karish and Tanin offshore gas fields in Israel, which are currently only at the preliminary stages of development;
- a substantial or extended decline in oil prices;
- production delays or interruptions in operations in the Prinos basin;
- breach, termination or reduced gas supply volumes under material Gas Supply Agreements;
- failure to comply with obligations under contracts, licences, permits, operating agreements and relevant legislation;
- the unavailability or high cost of future debt and equity financing;
- failure to compete effectively against other oil and gas exploration and production companies or in the domestic Israeli gas market;
- the discovery or production of less oil or gas than expected based on exploration, appraisal and development activities;

- a lower level, quality or production volume of crude oil and/or gas reserves than estimated or expected;
- changes to, disagreements in respect of or termination of the offtake agreement with BP;
- failure to obtain or access necessary equipment, raw materials, third party services and transportation systems;
- the occurrence of drilling, exploration and/or production risks or hazards;
- difficulties in retaining or hiring Directors, key members of management, technical, exploration, financial and operational service providers;
- wage demands or work stoppages by unionised employees;
- claims or litigation brought against the Group;
- increased taxes, audits by tax authorities and liabilities in respect of historic tax periods or the conviction of certain of the Group's employees for tax treatments arbitrarily imposed by Kavala Oil S.A.;
- failure to comply with health and safety and environmental regulations;
- breach of financial covenants;
- inability to exercise control over certain activities for assets where the Group does not maintain the operatorship;
- failure to obtain Kerogen Capital's consent to significant matters affecting Energean Israel's operations;
- exposure to foreign exchange and inflation risks;
- instability, armed conflict, terrorist activities or political instability in Israel, the Middle East or North Africa;
- financial or political instability in Greece; and
- adverse sovereign action by governments of, or changes to local laws in, the countries in which the Group operates.

Should one or more of these risks or uncertainties materialise or should any of the assumptions underlying the above or other factors prove to be incorrect, the Group's actual future business, results of operations and/or financial condition, performance, prospects, anticipated growth, strategies or opportunities could differ materially from those described herein as currently anticipated, believed, estimated or expected.

Investors or potential investors should not place undue reliance on the forward looking statements in this Prospectus. Investors should read the sections of this Prospectus titled "*Risk Factors*", "*Overview of Israeli and Greek Oil and Gas Industry*", "*Business Overview*" and "*Operating and Financial Review*" for a more complete discussion of the factors that could affect the Group's future performance and the markets in which it operates. In light of the possible changes to the Group's beliefs, assumptions and expectations, the forward looking events described in this Prospectus may not occur. Additional risks currently not known to the Group or that the Group has not considered material as of the date of this Prospectus could also cause the forward looking events discussed in this Prospectus not to occur.

Forward looking statements involve inherent risks and uncertainties and speak only as of the date they are made. Such forward-looking statements contained in this Prospectus speak only as of the date of this Prospectus. The Company, the Directors, the Major Shareholders and the Banks expressly disclaim any obligation or undertaking to update these forward-looking statements contained in the Prospectus to reflect any change in their expectations or any change in events, conditions, or circumstances on which such statements are based unless required to do so by applicable law, the Prospectus Rules, the Listing Rules, or the Disclosure Guidance and Transparency Rules of the FCA.

PART 3
DIRECTORS, SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors	Simon Heale, Non-Executive Chairman Matthaios Rigas, Chief Executive Officer Panagiotis Benos, Chief Financial Officer Andrew Bartlett, Senior Independent Director Efstathios Topouzoglou, Non-Executive Director David Bonanno, Non-Executive Director Robert Peck, Independent Non-Executive Director Ohad Marani, Independent Non-Executive Director Karen Simon, Independent Non-Executive Director
Company Secretary	Michelle Churchward
Registered and head office of the Company	Energean Oil & Gas plc 21 Gloucester Place London W1U 8HR United Kingdom
Joint Global Co-ordinators, Joint Bookrunners and Joint Sponsors	Citigroup Global Markets Limited Citigroup Centre 33 Canada Square London E14 5LB United Kingdom Morgan Stanley & Co. International plc 25 Cabot Square Canary Wharf London E14 4QA United Kingdom
Joint Global Co-ordinator and Joint Bookrunner	Stifel Nicolaus Europe Limited 150 Cheapside London, EC2V 6ET United Kingdom
Joint Bookrunner	RBC Europe Limited Riverbank House 2 Swan Lane London, ECR4 3BF United Kingdom
Co-lead Managers	Natixis 47 quai d'Austerlitz 75013 Paris France Poalim IBI Underwriting & Issuing LTD Shalom Tower, 9 Ahad Ha'am St. Tel Aviv 652101 Israel Société Générale 29 Boulevard Haussmann 75009 Paris France
Financial Adviser	N. M. Rothschild & Sons Limited New Court St Swithin's Lane London EC4N 8AL United Kingdom

English and U.S. legal advisers to the Company	White & Case LLP 5 Old Broad Street London EC2N 1DW United Kingdom
Greek legal advisors to the Company	Charalambides & Partners Law Firm 15, Pindarou Street 10673 Athens Greece
Israeli legal advisors to the Company	Meitar Liquornik Geva Leshem Tal, Law Offices Abba Hillel Silver Rd 16 Ramat Gan 5250608 Israel
English and U.S. legal advisers to the Joint Global Co-ordinators, Joint Bookrunners and Joint Sponsors	Herbert Smith Freehills LLP Exchange House Primrose Street London EC2A 2EG United Kingdom
Greek legal advisors to the Joint Global Co-ordinators, Joint Bookrunners and Joint Sponsors	Papapolitis & Papapolitis Vas. Sofias 16 10674 Athens Greece
Israeli legal advisors to the Joint Global Co-ordinators, Joint Bookrunners and Joint Sponsors	Goldfarb Seligman & Co. Ampa Tower 98 Yigal Alon Street Tel Aviv 6789141 Israel
Reporting Accountants	Deloitte LLP 2 New Street Square London EC4A 3BZ United Kingdom
Auditors	Ernst & Young LLP 1 More London Riverside London SE1 2AF
Registrars	Computershare Investor Services PLC The Pavilions Bridgwater Road Bristol BS13 8AE United Kingdom

PART 4
EXPECTED TIMETABLE OF PRINCIPAL EVENTS AND GLOBAL OFFER STATISTICS

The dates and times given in the table below in connection with the Global Offer are indicative only and are based on the Company's current expectations and may be subject to change without notice. All times shown in this Prospectus are in London times unless otherwise stated.

Expected timetable of principal events

Event	Time and Date (2018)
Announcement of Offer Price and allocation	7.00 a.m. on 16 March 2018
Commencement of conditional dealings on the London Stock Exchange	8.00 a.m. on 16 March 2018
Admission and commencement of unconditional dealings in the Shares on the London Stock Exchange	8.00 a.m. on 21 March 2018
Crediting of Shares to CREST accounts	21 March 2018
Despatch of definitive share certificates (where applicable)	On or before 4 April 2018

It should be noted that, if Admission does not occur, all conditional dealings will be of no effect and any such dealings will be at the sole risk of the parties concerned. Temporary documents of title will not be issued.

Global Offer statistics	
Offer Price (per Share)	£4.55
Number of Shares being offered in the Global Offer	72,592,016
Percentage of the issued Share capital being offered in the Global Offer	48%
Number of Shares in issue following Admission	152,823,238
Market capitalisation of the Company at the Offer Price	£695.3 million
Estimated gross proceeds of the Global Offer to the Company	£330 million
Estimated net proceeds of the Global Offer receivable by the Company[(1)]	£321 million

Notes:

(1) The estimated net proceeds receivable by the Company are stated after deduction of the estimated underwriting commissions and other fees and expenses of the Global Offer (including VAT) payable by the Company, which are currently expected to be approximately £9 million.

PART 5
BUSINESS OVERVIEW

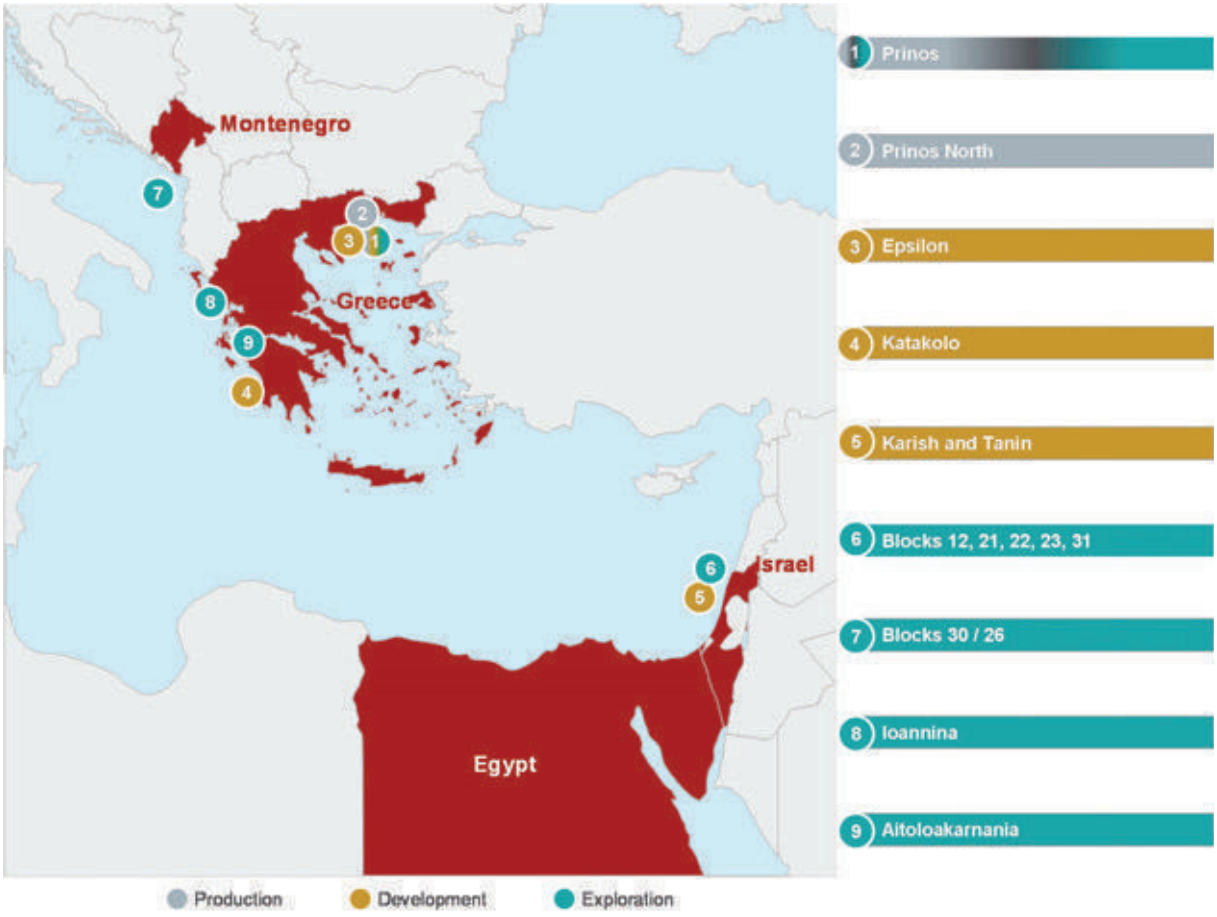
Investors should read this Part 5 "Business Overview" in conjunction with the more detailed information contained in this Prospectus including the financial and other information appearing in Part 6 "Overview of Israeli and Greek Oil and Gas Industry" and Part 11 "Operating And Financial Review". Unless otherwise indicated, the financial information in this section has been extracted without material adjustment from the Group's audited historical consolidated financial information contained in Section B of Part 13 "Consolidated Historical Financial Information" of this Prospectus.

1. Introduction

Energean is an independent oil and gas exploration and production ("**E&P**") company focused on the exploration, development and production of what the Directors believe to be attractive oil and gas assets in the Eastern Mediterranean, including Greece, Israel, the Adriatic and North Africa. Energean's strategy is to create a profitable and returns-focused business with sustainable growth prospects by leveraging the Group's experience and expertise in identifying, acquiring, developing and operating oil and gas assets in this region. The Directors' objective is to create the leading independent E&P company in the Eastern Mediterranean by pursuing an active development programme to add value across its portfolio.

Since its establishment in 2007, Energean has acquired a diverse portfolio of producing assets, appraisal and development opportunities and exploration prospects, Energean is the operator of the majority of the key assets in its portfolio. Energean's total 2P reserves were 50.0 MMbbls of oil and 6.0 Bcf of gas and its total 2C resources were 55.8 MMbbls of oil and 2.4 Tcf of gas as of 31 October 2017 (including Karish and Tanin resources at 100%, of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement).

Assets and Operations



Asset Type	Greece	Israel	Montenegro
Developed producing	Prinos (oil) Prinos North (oil) South Kavala (gas)(1)		
Undeveloped	Epsilon (oil) Prinos (oil) Prinos North (oil) Katakolo (oil and gas)	Karish (gas) Tanin (gas)	
Exploration	Prinos South Kavala Ioannina Aitoloakarnania	Karish Tanin Blocks 12, 21, 22, 23, & 31	Block 4218-30 Block 4219-26 (Montenegro PCC)

Notes:
(1) Gas used only for the Group's own purposes and is not sold.

Producing Assets

Energean's current developed producing assets, Prinos and Prinos North, are offshore oil fields located in Greek waters. The Group produced on average approximately 2,576 bopd (2,709 bopd excluding 18 days of scheduled maintenance during which the plant was shut down) and 3,190 bopd from Prinos during the years ended 31 December 2017 and 2016, respectively, and approximately 227 bopd from Prinos North for the year ended 31 December 2017 (239 bopd excluding 18 days of scheduled maintenance during which the plant was shut down), with a future investment plan from 2018 of approximately US$353 million through 2021 and approximately US$65 million from 2021 to 2034 underway to increase production. This is the remaining anticipated expenditure under the Prinos basin development plan, with US$173.3 million already having been spent from 2015 to 31 October 2017. According to the CPR prepared by NSAI (the "**NSAI Prinos CPR**"), Prinos, Prinos North and Epsilon held 39.5 MMbbls of 2P oil reserves and 6 Bcf of 2P gas as of 31 October 2017. All current oil sales are managed through the BP Offtake Agreement under which BP typically collects on a quarterly basis.

Development Opportunities

The Group has development projects located in Israel and Greece. The Group's most significant undeveloped assets are the Karish and Tanin offshore gas fields located in Israel. Karish and Tanin are held by Energean Israel as lease holder and operator and the Group currently holds a 50.0001% voting interest in Energean Israel, with 49.9999% held by Kerogen, and a 50% economic interest, which is expected to rise to 70% economic and voting interest subject to the taking of a final investment decision by 31 March 2018, pursuant to a subscription agreement with Kerogen). Karish and Tanin had an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of condensate and light oil (contingent 2C resources) as of 31 October 2017, according to the CPR prepared by NSAI in respect of Karish and Tanin (the "**NSAI Israeli CPR**") (setting out Karish and Tanin resources at 100%, of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement).

These Israeli assets were acquired in 2016 and their development will materially increase the scale of the Group's operations with first gas targeted for 2021. The Karish field will be developed first (Phase 1) with other identified prospects and leads within both the Karish and Tanin lease blocks identified for future development after first gas. The Group has entered into a commercial partnership with TechnipFMC for the construction of an FPSO and subsurface facilities at the Karish and Tanin fields. The FPSO design would allow for future developments, both within the Karish and Tanin blocks and beyond, to be tied back. This would enable Energean to develop its assets in the region and provide a revenue stream should near- or far-field third party discoveries be tied back to the FPSO and associated infrastructure. The Group has entered into the Technip EPCIC Contract with TechnipFMC, thereby reducing the Group's exposure to construction and development risk. Capital expenditure for Phase 1 of the development, expected to be completed by the first quarter of 2021, is expected to be approximately US$1.6 billion (plus an additional US$371 million in other costs, including deferred payments).

The Group's Greek undeveloped assets are located in the Prinos basin (Epsilon, Prinos and Prinos North fields) Ioannina, Aitoloakarnania and Katakolo blocks. According to the CPR prepared by NSAI in respect of the Prinos basin fields, the Group had 22.9 MMbbls of oil and 5.3 Bcf of gas classified as contingent 2C resources in Greece as of 31 October 2017.

Exploration Prospects

In addition, the Group has a focused exploration strategy with several exploration prospects in Greece, Montenegro and Israel. As of 31 October 2017, the Group's exploration portfolio had best estimate unrisked prospective resources estimated at 4.3 Tcf of natural gas (3.3 Tcf in prospects, 1.0 Tcf in leads) and 410.8 MMbbls of liquids (77.3 MMbbls in prospects, 333.5 MMbbls in leads) according to the CPR prepared by NSAI in respect of Ioannina and the Group's Montenegrin assets (the "**NSAI Ioannina and Montenegro CPR**"), the NSAI Israeli CPR and the NSAI Prinos CPR (together the "**NSAI CPRs**"). The Group has a disciplined approach to managing exploration risk and has entered into farm-out agreements with Repsol in respect of two of its onshore Greek exploration assets, Ioannina and Aitoloakarnania, under which Repsol has taken a 60% interest in and operatorship of the assets. These fields have similarities to the geological structure of fields in Albania and Italy, which the Directors believe limits the Group's exploration exposure on these assets given Repsol's relevant technical knowledge of working in similar geological basins. Given the high levels of exploration drilling undertaken in Italy and Albania, the Directors believe that the similar tectonic domains in Western Greece and Montenegro, which remain relatively underexplored, represent an attractive focus for the Group's exploration strategy.

In 2017, Energean Israel participated in Israel's First Offshore Bid Round, submitting bids for block 12, which sits between the Karish and Tanin leases, and four additional adjacent blocks, 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and on 12 December 2017 Energean was awarded all five of the additional licences for which it had bid. Each licence has an initial validity period of three years, extendable following an application to be submitted by the licensee, no later than 3 months prior to the expiry of the initial period, by an additional three year period, subject to committing to drill an exploration well during such period and the conditions of the Petroleum Law. Block 12 is on trend with the Karish and Tanin discoveries, with several prospects identified on high quality 3D seismic which the Directors believe present an opportunity for low risk exploration which could be developed by a tie back to the FPSO. Energean considers the additional adjacent blocks to have attractive exploration potential. The proposed work programs for the blocks include reprocessing existing data available and acquiring new 3D seismic and drilling, subject to certain conditions, drilling an exploration well in Block 12. See *"—Overview of Assets—Israel—Blocks 12, 21, 22, 23, 31"* and *"Operating and Financial Review—Current Trading and Prospects"*.

Historical financial performance

For the ten months ended 31 October 2017, the Group had total revenue of US$38.4 million, with an operating loss of US$17.2 million. For the year ended 31 December 2016, the Group reported total revenue of US$39.7 million, with an operating loss of US$10.9 million.

2. Competitive strengths

The Directors believe that the Group benefits from the following key business strengths:

Experienced and proven offshore operator

The Group is the operator of the majority of its projects (including Prinos, Prinos North, South Kavala, Epsilon and Katakolo in Greece, Blocks 26 and 30 in Montenegro, and Karish, Tanin and Blocks 12, 21, 22, 23 and 31 in Israel). The Group considers its operational and technical knowledge to be core to its business, including its dedicated teams of geologists, geophysicists, and production and reservoir engineers, which can help Energean rapidly progress projects. This knowledge has been built up over the Group and its predecessors' more than 36 years of offshore operating experience in the Prinos basin through its subsidiaries. This experience and in-house capability support the Group in maintaining stable and risk-controlled production, providing a platform to acquire attractive assets and helping de-risk key development projects.

The Directors believe operatorship provides the Group with a degree of control over the quantum and timing of expenditure and the pace and direction of development and exploration activity, affording it the flexibility to progress projects at the most advantageous rate. The Group intends to also maintain a flexible and prudent approach to retaining or farming-out operatorship, depending on the nature of each asset and its financing structure.

Balanced portfolio of production, development and exploration assets

The depth and diversity of the Group's asset portfolio have been established to help ensure that Energean will not be over-dependent on its current producing assets, but will instead have a pipeline of assets at various stages of development so that commercial resources can be developed to replace the reserves consumed through production.

The Prinos and Prinos North oil fields are producing assets that provide revenue for the Group. Under the BP Offtake Agreement BP has agreed to purchase 100% of the Group's production from the Prinos basin assets until the later of 2025 or delivery of 25 MMbbls of oil. For a full description of the BP Offtake Agreement see "*—Offtake and marketing—BP Offtake Agreement*".

The Group also has undeveloped and exploration assets located in Israel, Greece, and Montenegro. In particular, the Directors believe that the development of the Karish and Tanin assets in Israel is substantially de-risked by analogous geological characteristics in nearby fields (including Tamar and Leviathan) and by the quality of the available seismic data. These assets also benefit from long licence terms and are not exposed to fluctuations in the oil price due to fixed floor prices in the majority of the Group's gas offtake agreements and local electricity indexation.

The production track record of the Group further demonstrates Energean's success as an offshore operator. In 2014, the Group produced on average 1,409 bopd which increased to 1,459 bopd and 3,490 bopd in 2015 and 2016, respectively. In 2016, the Group's total annual oil production exceeded 1 million barrels for the first time since 2002. Production averaged 2,803 bopd in 2017 with exit rate production at 31 December 2017 of 4,086 bopd. The 2017 average reflected asphaltene and drilling difficulties in the first half of 2017, which reduced production below previous projections. Production averaged 3,520 bopd in the two months ended 31 December 2017.

Strategically positioned to move quickly in an increasingly active region

The Group's operations are focused on the Eastern Mediterranean with the most significant assets located in Israel and Greece, which are both OECD countries and strategically attractive for investment. By maintaining a focused approach to the region in which it operates, the Directors believe the Group has developed strong relationships with all key stakeholders.

The Eastern Mediterranean has become an increasingly active E&P region. Recent discoveries of extensive gas fields in Egypt and Israel (the Zohr and Leviathan gas fields, respectively) have drawn attention and investment to the region. In Greece, Exxon Mobil, Total, Edison and Repsol have been attracted to the hydrocarbon sector and have acquired, or expressed interest in acquiring, Greek exploration blocks.

As an independent, locally-based exploration and production company, the Directors believe the Group is well positioned to compete and move swiftly on opportunities in the region.

Track record of value creation from acquired assets

The Group has a track record of creating value from its acquired assets. The Prinos basin licence was acquired in 2007. The NSAI Prinos CPR now estimates that the Prinos basin 2P assets will have a cumulative net cash flow (discounted at 10%) of approximately US$0.7 billion through 2035. Similarly, the Karish and Tanin leases were acquired in 2016 for US$148.5 million and ongoing royalties to the sellers (of which the Group has paid US$40.0 million and the remaining US$108.5 million of which is payable in ten equal annual payments). The acquisition of Karish and Tanin was completed at a lower US$/boe value than other discoveries in the region, with a US$/boe of 0.4 (excluding royalties to be paid to the sellers), while Zohr and Aphrodite had values of US$/boe of 1.4 and US$/boe 0.8 respectively (source: IHS Energy database—Herold).

The Prinos assets were acquired at what the Directors believe was a relatively advantageous valuation level. The Group has since then been able to secure a licence extension and has increased reserves through the technical reappraisal of the reservoir and drilling activity which has enabled the implementation of a low cost development plan. The value of Prinos to the Group is further enhanced by a four-year extension of Energean's long-term offtake agreement with BP from 2021 to 2025 for 100% of Prinos production. BP has been the Group's off-taker in the Prinos basin since 2013.

The Group acquired its Israeli assets in 2016 due to a regulatory requirement relating to the seller (see "*Overview of Israeli and Greek oil and gas industry—The Israeli gas industry—Competitive Environment*"). At the time, Karish and Tanin were stranded assets with no gas contracts in place. Since the acquisition of these leases, the Group has achieved a number of key milestones including the approval of the Karish and Tanin FDP in August 2017, the signing of 12 Gas Supply Agreements totalling an estimated 4.2 BCM per annum on an ACQ basis or 3.1 BCM per annum on a take or pay basis, based on Company best estimates, excluding the Or Gas Supply Agreement (assuming, inter alia, 95% uptime and reasonable maintenance) and the entry with TechnipFMC into

the Technip EPCIC Contract for the development of the Karish Gas Development (including an FPSO), the entire subsea infrastructure, the subsea pipeline and the onshore facilities up to a new-build gathering manifold at Dor adjacent to INGL's existing valve station, but excluding drilling). Based on publicly available information, the Group believes this would be the first FPSO in the Eastern Mediterranean. The Group seeks to continue to deliver on its strategic milestones, creating value and realising the valuation levels indicated in the CPRs.

Low cost producer with stable cash flow

The Group's producing asset base is relatively low cost and cash generative, which the Directors believe provides the Group with a greater degree of stability and flexibility.

Energean has historically been able to respond to volatility in the oil price by reducing its cost of oil production per barrel (excluding depreciation) for its production at the Prinos field largely through increased production, with cost of oil production per barrel falling from US$63/bbl in 2014 to US$41/bbl in 2015 and US$19/bbl in 2016, reaching US$26/bbl in 2017.

Experienced management team with an international oil industry track record

Energean's management team and staff are drawn from international oil companies, national oil companies, major and smaller independents and engineering contractors. Management's experience encompasses a broad range of projects, asset types, including offshore (shallow and deep water) assets, and exploration and production technology with over 200 years' combined experience in the oil and gas industry.

Energean has offices in the United Kingdom, Israel, Greece, Cyprus, Egypt and Montenegro. Energean's technical team has recently been expanded to support the move into deep water operations at Karish and Tanin in Israel.

World class technical partners and strong financial backing

The Directors believe that the growth of Energean's business has been supported by its strong relationships with customers, partnerships with industry-leading technical experts and financial backing from specialist investors.

BP

The Group entered into the BP Offtake Agreement in 2013 for the sale and purchase of crude oil from the Prinos, Prinos North and Epsilon fields in Greece.

Under this agreement, BP agrees to purchase 100% of the Group's entitlement to the crude oil production lifted from these fields. The agreement thus secures sales of crude oil produced and limits the Group's exposure to offtake risk. For a full description of the BP Offtake Agreement see "*—Offtake and marketing—BP Offtake Agreement*".

Repsol

The Directors believe that the Repsol farm-out agreement, which was signed in March 2017 in respect of the Ioannina and Aitoloakarnania assets, is an endorsement of the Group's exploration strategy, with Repsol acquiring the operator interest in such fields. Repsol works across the entire value chain in oil and gas exploration and production, transformation, development, and marketing of energy. Repsol operates in 37 countries. For a full description of the Repsol farm-out agreements see "*—Customers and major partners—Repsol*".

TechnipFMC

The Group has entered a contract with TechnipFMC to construct the FPSO and all subsea facilities at the Karish and Tanin fields. The contract with TechnipFMC is a lump sum, turnkey EPCIC contract, thereby limiting the Group's exposure to construction and development risk. TechnipFMC is one of the world's largest engineering contractors to the oil and gas industry, and a global leader in subsea, onshore/offshore and surface projects with more than 40,000 employees.

European Bank for Reconstruction and Development

In May 2016, EBRD extended a US$75 million senior loan facility to Energean to support the Group's growth and to finance the development of its oil producing assets in Greece. This was the first non-financial project supported by EBRD in Greece since 2008.

In July 2016, EBRD extended an additional US$20 million subordinated loan to Energean for oil and gas exploration in Greece. This loan facility has since been amended to permit drawdowns to be used for oil and gas exploration in Montenegro which allows the Group greater flexibility in the use of the EBRD funds across its Greek and Montenegrin exploration operations.

On 30 January 2018 the EBRD senior loan facility was amended and restated pursuant to the RBL Senior Facility Agreement to increase the facility amount up to US$180 million and extended to include other lenders including the Black Sea Trade and Development Bank, Banca Comerciala Intesa Sanpaolo Romania S.A. and the Export-Import Bank of Romania Eximbank SA.

Kerogen Capital

Kerogen Capital is an independent private equity fund manager specialising in the international oil and gas sector with approximately US$2 billion under management. Through its network it has access to significant pools of capital, both directly through the funds it manages as well as via co-investment. Kerogen Capital has been an instrumental investor for a range of independent oil and gas companies seeking development capital. The Group has entered into a strategic partnership with Kerogen for the development and commercialisation of the Karish and Tanin assets.

Third Point

Third Point LLC is an SEC-registered investment adviser based in New York City with more than US$17 billion under management, which focuses on event-driven, value-oriented investing. Third Point LLC manages its strategic investment in Energean through Third Point Hellenic Recovery Fund L.P. ("**TPHR**"), which was formed to invest in Greece and Cyprus. Third Point, a wholly-owned subsidiary of TPHR, has historically supported the Group through debt funding and remains one of its largest shareholders.

Prime Marine

One of Energean's founding shareholders is the majority shareholder of Prime Marine Corporation ("**Prime**"), a global provider of seaborne transportation of petroleum products and gas, and is the operator of a fleet of 34 double-hull tankers and LPG carriers with an overall carrying capacity of over 2.3 million deadweight tonnes.

Strong health and safety record

The Directors believe that Energean's strong health and safety and environmental ("**HSE**") performance is a key aspect of the Group's overall business success. The Group and its predecessors have operated in the Kavala and Thasos island areas in Greece, both of which are environmentally sensitive areas with high tourist activity, for 36 years and Energean has benefitted from this experience.

The Group believes the region's biodiversity and sustained popularity with tourists are a testament to the Group's ability to conduct its operations in an environmentally sound manner.

The Directors believe that Energean's health and safety record has been an important factor in its successful bids for licences and the Group is committed to maintaining the health and safety of its employees and other stakeholders.

3. Strategy

Energean's strategy is to create a profitable and returns-focused business with sustainable growth prospects by leveraging Energean's experience and expertise in the Eastern Mediterranean in identifying, acquiring, developing and operating oil and gas assets. The Directors intend to achieve this through:

Maximising production, reserves and cash flow generation from the Group's existing low-cost production base.

Energean aims to materially increase Prinos basin production and accompanying cash flow. The Group intends to achieve this through its existing development plan, which targets the monetisation of 2P reserves of 39.5 MMbbls of oil and 6.0 Bcf of gas and 2C resources of 22.9 MMbbls of oil and 5.3 Bcf of gas, as of 31 October 2017 according to the NSAI Prinos CPR. Energean's development plan from 2018 to 2021 includes: the drilling

of 25 new wells (with seven drilled from September 2015 to the end of 2017); the construction of an unmanned platform to exploit the Epsilon field adjacent to Prinos; and infilling drilling in the existing producing fields. The Directors believe that Energean's longstanding track record in the Prinos basin, operatorship of the majority of fields which the Group owns, and the ability to lower operating costs per barrel, will underpin its ability to maximise the commercial viability of its reserves and resources. Energean estimates average daily 2P production rates to increase to 4,864 bopd in 2018, as per the NSAI Prinos CPR as new infill wells are brought on stream in the Prinos complex, and is targeting 12,899 bopd by 2021.

Successfully developing Karish and Tanin, a material and de-risked opportunity

The Directors believe that Karish and Tanin represent a deliverable commercial development project that will ultimately transform the Group's business. With an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of liquids (2C resources) and 2.4 Tcf of natural gas and 70.9 MMbbls of liquids (best estimate unrisked prospective resources) as of 31 October 2017, according to the NSAI Israeli CPR (setting out Karish and Tanin resources at 100%, of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement), the Directors believe that these assets are highly strategic for the development of the Israeli energy market and can help to meet increasing Israeli demand, increase market competition and improve security of supply. In addition, the Directors believe that the Karish and Tanin development will position Energean as a significant player within the region. The FDP for Phase 1 of the project was approved by the Israeli government on 27 August 2017, with final investment decision expected in the first quarter of 2018 and first gas in the first quarter of 2021.

The development of the Karish and Tanin assets, as set out in the FDP, will primarily be funded by a combination of (i) the proceeds from the Global Offer; (ii) the proceeds of the Senior Credit Facility; (iii) existing equity and equity contributions from its partner Kerogen; and (iv) expected deferred payments (post-2021) of US$140 million in respect of the Technip EPCIC Contract and related US$125 million standby letter of credit. With respect to this funding, the Directors believe that Phase 1 of the Karish development will be fully funded to first gas.

The Directors believe that the project has been materially de-risked through a prudent and scalable development plan which includes a lump sum, turnkey EPCIC contract with TechnipFMC. and Energean has already secured Gas Supply Agreements which, subject to all conditions being satisfied, relate to an aggregate of up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis (or an average of approximately 3.3 to 3.8 BCM per annum on a take or pay basis, including the Or Gas Supply Agreement) with, inter alia, Dalia Power Energies Ltd. ("**Dalia**"); Or Power; Edeltech Group affiliates Ramat Negev Energy Ltd. ("**Ramat Negev**") and Ashdod Energy Ltd. ("**Ashdod Energy**"); Dorad Energy Ltd. ("**Dorad**"); Rapac affiliates I.P.P. Alon Tavor Ltd. ("**Alon Tavor**") and I.P.P. Ramat Gavriel Ltd. ("**Ramat Gavriel**"); and Israel Corporation affiliates OPC Rotem Ltd. ("**OPC Rotem**"), OPC Hadera Ltd. ("**OPC Hadera**"), Israel Chemicals Ltd. ("**ICL**") and Oil Refineries Ltd (Bazan Group) ("**ORL**") and Supergas Natural Ltd ("**Supergas**"). With regard to Dalia, ORL, ICL, Ramat Negev, Ashdod Energy, Dorad, OPC Rotem and partially to OPC Hadera, the Buyer's Facilities are operational power stations, while Alon Tavor and Ramat Gavriel are power stations which are currently under construction (holding a provisional licence) and Or Power is applying for a licence to construct a facility. Supergas is a gas marketing company.

Capitalising on growth opportunities in the prospective Eastern Mediterranean region

Energean is focused on the Eastern Mediterranean region including Greece and Israel, the Adriatic and North Africa regions. Energean's management have significant experience of operating within this region and are of the view that the Group's geographic focus, track record and relationships will allow it to exploit multiple avenues of growth over the medium term. These avenues comprise both development and exploration opportunities within Energean's current portfolio, including but not limited to, further Prinos basin development and exploration potential; exploration blocks in Aitoloakarnania, Ioannina and Montenegro; and various potential inorganic growth opportunities that would be aligned with the Group's strategy, including five blocks for which licences were awarded on 12 December 2017 to Energean Israel in Israel's First Offshore Bid Round concluded on 15 November 2017. See *"—Overview of Assets—Israel—Blocks 12, 21, 22, 23, 31"* and *"Operating and Financial Review—Current Trading and Prospects"*.

One example of such inorganic growth opportunities is the oil and gas industry in Cyprus which has experienced significant growth following the discovery of the Aphrodite gas field, with an estimated 4 Tcf of natural gas, in January 2012. Currently ENI, Total, Exxon Mobil and Qatar Petroleum are operating in the country, with Total and ENI having commenced drilling in Cyprus in July 2017. In February 2018, ENI announced the Calypso 1 gas discovery offshore Cyprus. Accordingly, Cyprus represents a further opportunity for the Group to expand its operations in its targeted region.

Maintaining a disciplined financial framework

The Group has successfully adopted a conservative balance sheet by careful working capital management and maintaining low levels of bank debt throughout the commodity down-cycle and periods of subdued oil prices. The Directors intend to maintain balance sheet flexibility going forward, with leverage minimised at the corporate level by managing contractor payables alongside disciplined capital deployment. The Group seeks to maintain strict investment criteria for new projects, typically targeting an unlevered internal rate of return of more than 15%. The Directors believe that this approach, alongside the Group's production, development and exploration opportunities, will underpin Energean's sustainable growth in the future.

4. History and structure of the Group

Energean was established in 2007 to undertake oil and gas exploration activities in the Eastern Mediterranean. Energean is the only oil and gas producer in Greece and, together with its predecessor business, has a 36-year track record of operating offshore and onshore assets in environmentally sensitive areas.

The Group's predecessor, with respect of the Prinos lease, was North Aegean Petroleum Co EPE ("**NAPC**"), a company formed by the Greek State and a consortium of companies (Denison Mines Corporation, Hellenic Petroleum S.A. ("**Hellenic Petroleum**"), Wintershall A.G. and White Shield) (the "**Consortium**"). NAPC began producing oil and gas at Prinos and South Kavala, respectively, in 1981. The assets were further developed in order to increase production in the 1980s and 1990s until production became uneconomical in 1998 due to low oil prices. In 1999 the Consortium, which had owned and operated the business, withdrew its involvement and the Greek State assigned maintenance and security of the assets to Eurotechniki Services S.A. ("**Eurotechniki**") which, in consortium with the then employees of NAPC, founded KOSA to run the operations at the assets. Regal Petroleum acquired a majority stake in Eurotechniki in 2003 and in 2005 acquired the remaining shares to become the sole shareholder in Eurotechniki. The Group subsequently acquired Regal Petroleum's shares in Eurotechniki in 2007. This acquisition was completed at what the Directors believe was an attractive price. Subsequently the Group undertook a corporate restructuring and introduced a new management team.

In 2008, the Group initiated a new development plan for the Prinos North and Epsilon fields. The Prinos licences were further extended (to be aligned with the 25 year term in accordance with the applicable legislative framework) in 2013. The BP Offtake Agreement was signed in April 2013 and is scheduled to remain in full force and effect (as amended in 2014, 2016 and February 2018) until the later of 1 November 2025 or delivery of 25 MMbbls of oil to BP. The Group's presence in Greece was further strengthened by the acquisition, in 2014, of licences for the Ioannina and Katakolo blocks and, in 2017, a further licence was signed for the Aitoloakarnania block. On 31 March 2017, Energean agreed to farm-out to Repsol a 60% working interest in the Ioannina and Aitoloakarnania blocks, Western Greece.

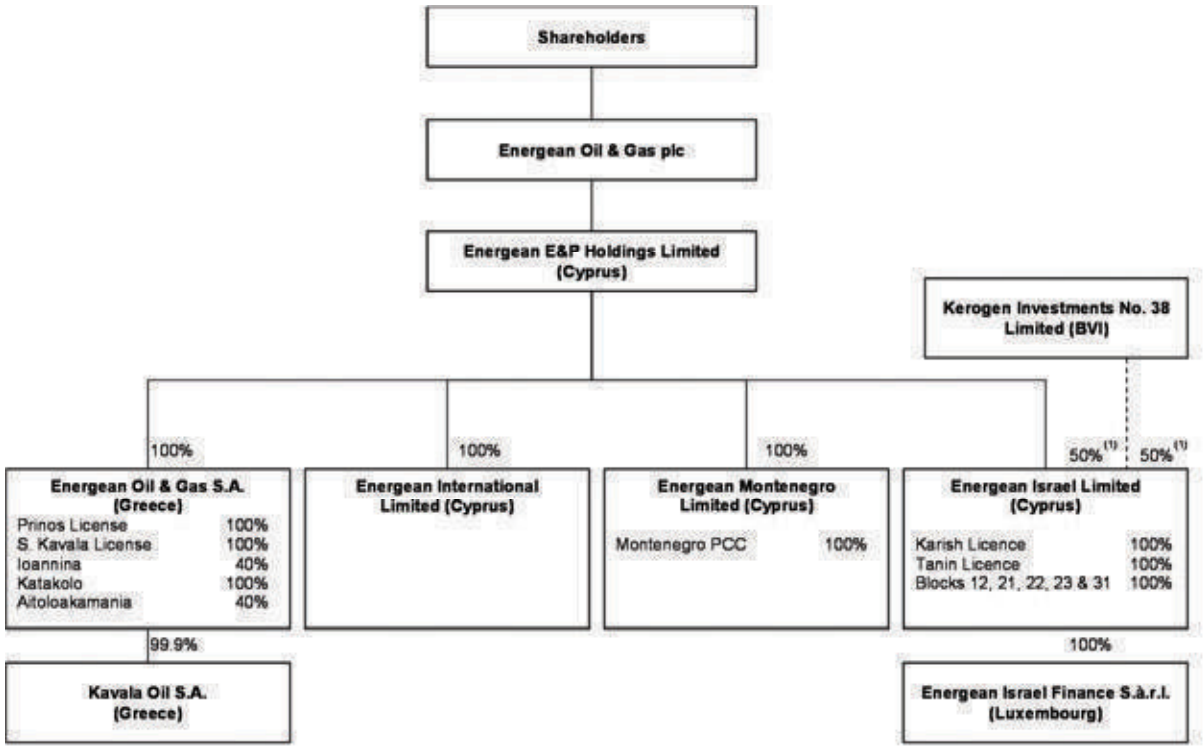
In 2010, the Group diversified its portfolio and began acquiring assets in other jurisdictions. In 2010 the Group acquired 100% of the concession rights for the East Magawish Block in the Gulf of Suez (Egypt) and in the same year entered into an asset purchase agreement with Pan Pacific Petroleum Pty. Ltd. ("**Pan Pacific**") while Groundstar Resources Inc. had entered into an asset exchange agreement with Pan Pacific for a 60% working interest and operatorship of the West Kom Ombo Block (Upper Egypt) with Pan Pacific 40%. The West Kom Ombo Block was given a 3 year exploration period extension in 2011 and, following subsequent extensions, the term of the 2nd and last exploration stage expired on 3 October 2017. In 2016 the Group bought the natural gas fields of Karish and Tanin (offshore Israel) from Noble, Delek and Avner Oil Exploration Limited Partnership ("**Avner**") and in 2017 a concession agreement was signed with Montenegro for exploration and production in the offshore Block 30 and Block 26.

In 2017, Energean Israel participated in Israel's First Offshore Bid Round. Energean Israel submitted bids for block 12 which sits between the Karish and Tanin leases, and four additional adjacent blocks, 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and on 12 December 2017 Energean Israel received awards for all five of the additional licences for which it had bid. See *"—Overview of Assets—Israel—Blocks 12, 21, 22, 23, 31"* and *"Operating and Financial Review—Current Trading and Prospects"*. Each licence has an initial validity period of three years, extendable following an application to be submitted by the licensee, no later than 3 months prior to the expiry of the initial period, by an additional three year period, subject to committing to drill an exploration well during such period and the conditions of the Petroleum Law.

Since its establishment in 2007, Energean has received investment from strong financial backers. In 2013, Third Point became a shareholder in the Group with an equity investment of US$60 million. In 2014, Third Point provided a senior secured loan of US$125 million to Energean, subsequently increased in 2015 to

US$179.7 million and converted to an equity interest in 2017. This was followed by a US$75 million senior borrowing base financing from EBRD in 2016. EBRD extended a further US$20 million subordinated loan facility to Energean in July 2016. In 2016 and 2017 Kerogen provided a US$40 million loan and an additional US$10 million investment in Energean Israel, which were converted to a 50% equity interest in 2017. On 30 January 2018, pursuant to the RBL Senior Facility Agreement, the EBRD senior loan facility was amended and restated to increase the facility amount up to US$180 million and extended to include other lenders including the Black Sea Trade and Development Bank and the Export-Import Bank of Romania Eximbank SA. In March 2018, the Group entered into the Senior Credit Facility for the provision of up to US$1.275 billion for the development of the Karish and Tanin assets.

The current organisational structure of the Group is as follows:



Notes:

(1) The Group currently has a 50% economic interest in Energean Israel, with 50.0001% of the voting rights. On 28 December 2017, Energean E&P Holdings entered into the Second EISL Subscription Agreement to acquire a further 20% interest in Energean Israel by means of a subscription of new shares in Energean Israel. It is expected that such subscription will complete in the first quarter of 2018, subject to FID by 31 March 2018.

5. Summary of reserves and resources

5.1 Report in respect of Karish and Tanin

NSAI has produced the NSAI Israeli CPR, dated 5 January 2018, on Energean's Israel reserves and resources relating to the Karish and Tanin fields. NSAI has prepared its assessment of Energean's Israel asset base as of 31 October 2017 and has reviewed and incorporated field studies and data that were undertaken up to that date.

5.2 Reports in respect of Greek assets

NSAI has produced the NSAI Prinos CPR, dated 26 January 2018, on Energean's reserves and resources relating to the Prinos, Prinos North and Epsilon fields. NSAI has reviewed and incorporated field studies and updated performance data that were available up to 31 October 2017.

NSAI has produced the NSAI Ioannina and Montenegro CPR, dated 22 November 2017, on Energean's reserves and resources relating to the Ioannina field and Blocks 30 and 26. NSAI has prepared its assessment of Energean's asset base at these fields as of 31 October 2017, and has reviewed and incorporated field studies and updated data that were available up to that date.

NSAI has produced the NSAI Katakolo CPR dated 23 January 2018, on Energean's reserves and resources relating to the West Katakolo field. NSAI has prepared its assessment of Energean's asset base at Katakolo as of 31 October 2017.

5.3 Reserves and contingent resources

According to the NSAI CPRs, the Group had the following reserves and resources as of 31 October 2017.

Oil

Region	Asset	Reserves (MMbbls)			Contingent Resources(*) (MMbbls)		
		1P	2P	3P	1C	2C	3C
Israel(1)(2)	Karish	—	—	—	16.1	28.7	45.3
	Tanin	—	—	—	2.5	4.1	6.4
Greece	Prinos	12.8	17.8	25.2	2.7	15.6	29.1
	Prinos North	2.2	3.3	4.4	1.1	2.4	3.8
	Epsilon	13.0	18.4	21.9	0.0	0.1	3.7
	Athos	—	—	—	1.6	2.4	3.5
	Delta	—	—	—	0.7	1.6	2.8
	Kazaviti	—	—	—	0.4	0.9	1.2
	Prinos D Reservoir	—	—	—	—	—	0.1
	Katakolo	6.3	10.5	16.3	—	—	—
Total		**34.3**	**50.0**	**67.8**	**25.1**	**55.8**	**95.9**

Gas

Region	Asset	Reserves (Bcf)			Contingent Resources(*) (Bcf)		
		1P	2P	3P	1C	2C	3C
Israel(1)(2)	Karish	—	—	—	1,212.7	1,630.8	2,098.9
	Tanin	—	—	—	560.2	785.9	1,069.0
Greece	Prinos	1.5	2.9	4.8	0.9	4.9	9.2
	Prinos North	0.1	0.3	0.4	0.2	0.4	0.6
	Epsilon	1.4	2.8	3.8	—	—	1.1
	Katakolo	—	—	—	3.7	6.2	9.6
Total		**3.0**	**6.0**	**9.0**	**1,777.7**	**2,428.2**	**3,188.4**

Notes:

(*) Approximately 92% of the contingent resources covered by the NSAI Israeli CPR are subject to only two contingencies—namely upon project sanctioning and the availability of project financing. The financing for Phase 1 of the Karish-Tanin Development, principally comprising the Senior Credit Facility and a portion of the proceeds of the Global Offer, will be in place as of the date of Admission. The project sanctioning condition will be satisfied at the point that the Group proceeds with the final investment decision, which is in the control of the Group and is expected to take place within 30 days following Admission. The Directors believe that, on satisfaction of the above two contingencies, these contingent resources will satisfy the criteria to be classified as reserves. The Group intends to commission an update of the NSAI Israeli CPR as of 30 June 2018, by which point the two contingencies above are anticipated to have been satisfied and these contingent resources would be re-classified as reserves. In addition, the contingent resources in the Karish Field B Sand (which represent the remaining approximately 8% of the contingent resources covered by the NSAI Israeli CPR) are further contingent upon sufficient flow testing to establish commercial productivity. See also Part 1 "*Risk Factors—Risk relating to the Group's business and industry—The level of the Group's crude oil and gas reserves and resources and their quality and production volumes and expected cash flows are inherently uncertain and may be lower than estimated or expected" and Part 2 "Important Information—Reserve and resource reporting*".

(1) Tables show 100% of Karish and Tanin resources, of which the Group's effective working interest is 50%, expected to rise to 70% subject to taking FID by 31 March 2018 pursuant to the Second EISL Subscription Agreement.

(2) Gross gas resources. The NSAI Israeli CPR presents total contingent resources applying a 2.5% shrinkage for processing, fuel and flare. This gives totals of 1,728.5 (Low Estimate, 1C), 2,356.1 (Best Estimate, 2C) and 3,088.7 (High Estimate, 3C). Totals shown here are based on numbers presented by NSAI in their breakdown by field and as such the totals may differ from summary figures.

5.4 Prospective resources

The Group's prospective resources include leads and prospects. The NSAI CPRs define a "**prospect**" as a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target and a "**lead**" as a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. The tables below present the Group's best estimate unrisked prospective resources in prospects and leads as set out in the NSAI CPRs.

Prospects

According to the NSAI CPRs, the Group had the following prospects as of 31 October 2017.

		Prospects—Prospective Resources Unrisked					
		Low Estimate		Best Estimate		High Estimate	
Region	Asset	Liquids (MMbbls)	Gas (Bcf)	Liquids (MMbbls)	Gas (Bcf)	Liquids (MMbbls)	Gas (Bcf)
Israel	Karish	15.4	1240.8	31.1	2002.8	62.5	2928.0
	Tanin	9.6	310.5	39.8	443.9	180.7	742.0
Greece	Prinos basin	1.8	—	2.6	—	3.7	—
Montenegro	Blocks 26 & 30	0.5	370.5	3.8	855.1	29.1	1,652.1
Total		**27.3**	**1,921.8**	**77.3**	**3,301.8**	**276.0**	**5,322.1**

Leads

According to the NSAI CPRs, the Group had the following leads as of 31 October 2017.

		Leads—Prospective Resources Unrisked					
		Low Estimate		Best Estimate		High Estimate	
Region	Asset	Liquids (MMbbls)	Gas (Bcf)	Liquids (MMbbls)	Gas (Bcf)	Liquids (MMbbls)	Gas (Bcf)
Greece	Prinos basin	4.6	—	6.3	—	8.6	—
	Ioannina (Raeko)[(1)]	57.8	31.0	187.1	103.3	410.0	249.0
Montenegro	Blocks 26 & 30	41.0	399.8	140.1	911.4	443.2	1,739.5
Total		**103.4**	**430.8**	**333.5**	**1,014.7**	**861.8**	**1,988.5**

(1) Representing 100% unrisked prospective resources at Ioannina (Raeko), of which the Group has a 40% working interest.

PROSPECTIVE RESOURCES ARE THOSE DEPOSITS THAT ARE ESTIMATED, ON A GIVEN DATE, TO BE POTENTIALLY RECOVERABLE FROM UNDISCOVERED ACCUMULATIONS. FREQUENTLY, THIS MAY BE IN AREAS WHERE GEOSCIENCE AND ENGINEERING DATA ARE UNABLE TO CLEARLY DEFINE THE AREA AND VERTICAL RESERVOIR LIMITS OF COMMERCIAL PRODUCTION FROM THE RESERVOIR BY A DEFINED PROJECT. SEE PART 1 "*Risk Factors—Risks relating to the Group's business and industry—The level of the Group's crude oil and gas reserves and resources and their quality and production volumes and expected cash flows are inherently uncertain and may be lower than estimated or expected*".

For details of the plans in place to realise the prospective resources identified in the table above please see "*—Field development for the Prinos Basin*" and " *—Overview of Assets—Israel—Development of Karish and Tanin Prospects*".

6. Overview of assets

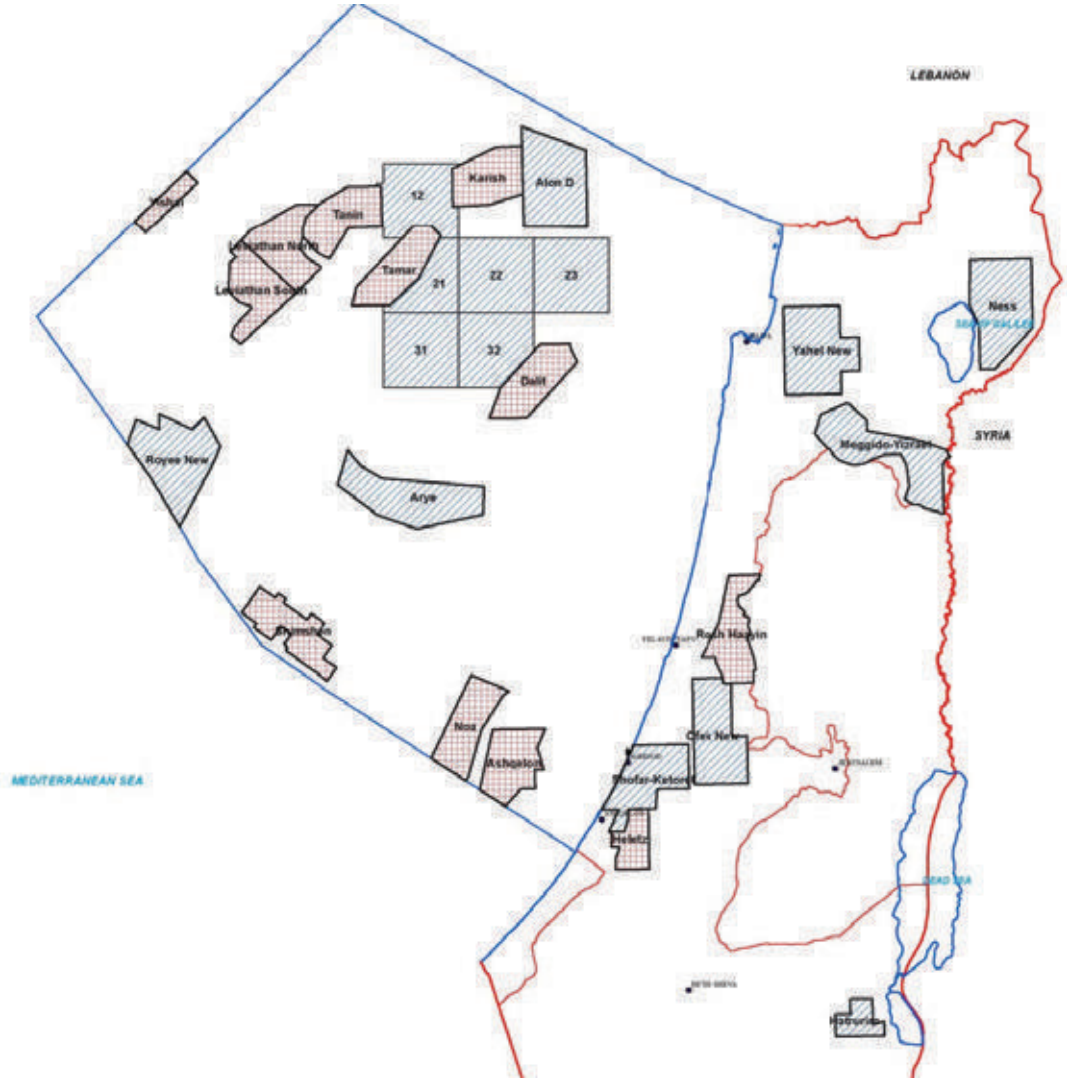
The following table summarises the current producing, development and exploration assets of the Group.

	Asset	Location	Operator	Area (km^2)	Energean's working interest	Partner's working interest	Expiration date
1.	Karish	Israel	Energean	250	50%(1)	50% (Kerogen)	August 2044
2.	Tanin	Israel	Energean	250	50%(1)	50% (Kerogen)	August 2044
3.	Prinos	Greece	Energean		100%	N/A	2034
4.	Prinos North	Greece	Energean		100%	N/A	2034
5.	South Kavala	Greece	Energean		100%	N/A	2017
6.	Epsilon	Greece	Energean	105	100%	N/A	2039
7.	Katakolo	Greece	Energean	545	100%	N/A	August 2041
8.	Ioannina	Greece	Repsol	4,187	40%	60% (Repsol)	October 2048
9.	Aitoloakarnania	Greece	Repsol	4,360	40%	60% (Repsol)	2049
10.	Block 26	Montenegro	Energean	63	100%	N/A	2020
11.	Block 30	Montenegro	Energean	275	100%	N/A	2020
12.	Block 12	Israel	Energean	364.9	50%(1)	50% (Kerogen)	2021
13.	Block 21	Israel	Energean	228.2	50%(1)	50% (Kerogen)	2021
14.	Block 22	Israel	Energean	400	50%(1)	50% (Kerogen)	2021
15.	Block 23	Israel	Energean	400	50%(1)	50% (Kerogen)	2021
16.	Block 31	Israel	Energean	400	50%(1)	50% (Kerogen)	2021

(1) The Group currently has a 50% economic interest in Energean Israel, with 50.0001% of the voting rights. On 28 December 2017, Energean E&P Holdings entered into an agreement to acquire a further 20% interest in Energean Israel by means of a subscription of new shares in Energean Israel. It is expected that such subscription will complete in the first quarter of 2018.

6.1 Israel

Regional overview



The Israeli gas sector has experienced significant growth since the discovery of gas fields offshore in the 1990s. Since those initial, smaller discoveries, exploration activity in the region has identified further, significant, gas structures. The regulation of the Israeli gas sector is relatively favourable to new market entrants as the Israeli government has recently taken measures to create regulatory stability, encourage competition, including with the introduction of the Protection Decision and by increasingly restricting the use of coal and heavy fuel oils, thereby placing a greater reliance, domestically, on natural gas.

The Karish and Tanin fields were discovered by Noble and Delek who initially held the leases for those assets. As a result of the Noble and Delek duopoly being broken up by the Israeli government, Energean acquired the leases for Karish and Tanin in 2016 from Noble, Delek and Avner for US$148.5 million, of which the Group has paid US$40.0 million and the remainder of US$108.5 million is payable in ten annual payments in addition to royalties to the sellers. This acquisition was finalised and approved by the Israeli government in December 2016. See Part 16 *"Additional Information—Material Contracts—Karish and Tanin sale and purchase agreement"*.

In December 2016, Kerogen, a private equity fund manager focused on oil and gas, agreed to invest US$50 million in Energean Israel and to participate with a 50% shareholding in Energean Israel. In December 2017, Energean E&P Holdings entered into the Second EISL Subscription Agreement and agreed to acquire a further 20% interest in Energean Israel by means of a subscription of new shares in Energean Israel, which would reduce Kerogen's shareholding in Energean Israel to 30% subject to the Group taking FID by 31 March 2018 (or 30 June 2018 if Kerogen consents). For more information on the terms of this acquisition, see Part 16 *"Additional Information—Material Contracts—Second EISL Subscription Agreement"*.

For more information on the Israeli Gas sector see Part 6 "*Overview of Israeli and Greek Oil and Gas Industry—Israeli Gas Industry*".

Karish

Overview

The Karish field is an undeveloped asset in the Levantine Basin of the eastern Mediterranean and is located north of Israel's EEZ approximately 80km offshore Israel. The water depth is about 1,700m. Karish lies some 25km northeast of Noble's Tamar field development.

Lease details—Karish

Area km^2	250
Original grant date	11 August 2014 (lease deeds first granted on 24 December 2015, amended on 25 April 2017)
Expiry	August 2044
Licence type	Tax Royalty
Main plays	prolific Early-Miocene Tamar Sands play
Number of active wells	0
Partner	Kerogen
Energean Israel's legal interest	100%
Energean's effective working interest:	50%
Data available	3D seismic acquired in 2010 plus full data set from the Karish-1 exploration well
Royalties payable	To Delek and Avner (which have since merged together into Delek): 7.5% increasing to 8.25% on the date on which Energean is first required to make payments on account of the petroleum levy (the "**Levy**") pursuant to the Taxation of Profits from the Natural Resources Law, 5771-2011, less royalties due under existing royalties for the benefit of other third parties to be paid directly to such third parties. The royalty is calculated on the value of the total amount of gas and condensate produced at the well head without any deduction (except for gas and condensate used in the production process). The royalty is expected to increase to 8.25% in 2024. To the State of Israel: According to Petroleum Law, 5712-1952, a leaseholder is required to pay royalties of 1/8 (12.5%) of the volume of oil produced to the State. The leaseholder will pay the market value of the royalties according to the value of the gas or oil at the well head and not according to selling price to the end customer.
Tax regime	Ordinary corporate income tax rate of 23%. Oil Profits tax (the Levy): According to the Oil Profits taxation law (L.5771-2011), the maximum monthly levy rate, based on the corporate income tax rate from 2018 onwards, may reach up to 46.8%. The proportion of the Levy on the royalties payable to Delek and Avner (which have since merged together into Delek) and other third parties is paid directly by Delek and such third parties or withheld by Energean when paying the royalty and is therefore fully deductible from the cumulative revenue calculation.

Lease details—Karish

	For more details on the Levy see "*Regulatory Overview—Regulatory and legislative framework in Israel—Fiscal Regulations*".
Hydrocarbons export regime	Permits the production of natural gas and oil condensates only. While the export of natural gas is prohibited, oil condensates are permitted for export. The production and/or export of crude oil would require the amendment of the leases via an addition of a new chapter to the lease by the Petroleum Commissioner. At this time it is not possible to assess the potential conditions or likelihood under which Energean might be granted an export quota.
Other provisions applicable to Karish	Permits required for the operation of the production system; local content requirements (lease holder of both leases to invest in local content of no less than US$80 million over eight years); requirements regarding abandoning the production system and plugging wells; bank guarantees to be provided as collateral for fulfilling the terms of the leases and terms for their forfeiture; guidelines for environmental protection, safety, and security; provisions regarding liability, indemnification and insurance.

Reserves and/or resources

Karish 2C contingent resources have been independently audited by NSAI at 1,630.8 Bcf for natural gas and 28.7 MMbbls for liquids. Best estimate unrisked prospective resources have been independently audited at 2,002.8 Bcf for natural gas and 31.1 MMbbls for liquids as per the NSAI Israeli CPR.

Field technical background

The Karish main field, located within the Karish lease, was discovered in 2013 and is located 25km northeast of the currently-producing Tamar field. The Karish main field is approximately 16km^2 with a maximum estimated hydrocarbon column of 300 to 400m.

The Levantine Basin, in which the Karish and Tanin assets are located, contains up to 10,000m of Mesozoic and Cenozoic rocks above a rifted Triassic-Lower Jurassic terrain. The northern boundary of the Levantine Basin is defined by Cyprus and the Larnaca Thrust Zone, and its northwestern margin by the Eratosthenes Seamount. The Nile Delta Cone and the East Mediterranean coast define its southwestern and eastern margins. The pressure-volume-temperature models carried out in Karish demonstrate normal temperature and pressure for the depth of the reservoir. The field has strong vertical and lateral connectivity with faulting not expected to compartmentalise and a single gas-water contact has been evidenced by the seismic available for the Karish main field.

The Karish asset itself is a large two-way closure that sits on the southern upthrow side of a large down-to-the-north fault and is defined by 3D seismic data (2009 and 2010 Noble surveys). The Karish main field was evaluated by Noble in 2013 using a single discovery well ("**Karish-1**") which was drilled by Noble to a depth of approximately 4,800m (true vertical depth subsea ("**TVDSS**")). The discovered hydrocarbons within the Karish and Tanin Leases are contained with the Early Miocene submarine fan deposits of the Tamar Sands. Seismic data further suggests continuity of the main Miocene sands between the Leviathan, Tanin and Karish fields.

The Tamar Sands are further subdivided into more detailed reservoir units (A-D Sands, with A being stratigraphically the youngest). The C Sands at Karish are approximately 130m TST and are interpreted to be extensive across the entire structure. The fluid in the Karish C reservoir is substantially richer than that discovered in the other Levantine basin fields such as Tanin, Tamar and Leviathan. The B sands at Karish, while thinly bedded, can be identified on the available image logs. The reservoir at Karish is well defined and well understood as it is analogous to the reservoir sands at Tamar and Leviathan and the 3D seismic data available is of excellent quality. The Directors believe that the sub-surface risk of developing the Karish field will be

mitigated given the similarities with the nearby Tamar and Leviathan fields (analogies and proximity as described above).

Within the Karish field a seismic amplitude anomaly associated with the C sands has been identified. This anomaly was tested by Karish-1, and other similar anomalies have been observed in the Karish North Upthrown prospect and the Karish Northeast prospect. Given that the amplitude anomalies are consistent with the structure of the reservoir (the anomaly aligns with the depth contours) the Directors have a high degree of confidence in the success of these prospects. The NSAI Israeli CPR puts the probability of geological success of the Karish North Upthrown prospect and the Karish Northeast prospect at 75% and 70% respectively. The Group is undertaking further studies to better quantify this seismic response of the amplitude anomalies including: seismic reprocessing of original field tapes, pre-stack depth migration, rock petrophysics and pre stack amplitude studies (AVO, AI and EAI). The Group is developing plans for Karish North exploration expected in 2020.

The NSAI Israeli CPR identified several further prospects in the Karish field and has audited prospective resources in respect of several of these including the Karish North Upthrown and the Karish Main Block (with best estimate unrisked gross prospective resources of 7.3 MMbbls of liquids and 595.9 Bcf of gas and 4.4 MMbbls of liquids and 422.0 Bcf of gas, respectively).

The Group believes there is the potential for reclassification of certain prospective resources to reserves in the D sands of Karish Main upon appraisal, expected in the second or third quarter of 2019.

Field capex plan and outlook

Energean (in conjunction with its strategic partner Kerogen) has planned to develop the Karish and Tanin fields with a new-build, fully-owned, FPSO and to invest approximately US$1.6 billion in capex (plus an additional US$371 million in other costs, including deferred payments, as set out in the table below) in Phase 1, which is the phase running until production of first gas from the Karish main field, expected in 2021. The anticipated project costs include all uses including deferred acquisition payments to Delek and Avner (which have merged together into Delek) and financing costs.

The Phase 1 project costs are expected to be financed through borrowings comprising the Senior Credit Facility of up to US$1.275 billion and equity financing of approximately US$465.8 million (to be funded by the Group and Kerogen, as described below, in addition to the US$60 million of equity which has already been funded), expected deferred payments (post-2021) of US$140 million in respect of the Technip EPCIC Contract and related US$125 million standby letter of credit. This standby letter of credit is designed to fund any potential cost overrun associated with the project which may or may not materialise at the end of the construction period.

In respect of equity financing, Kerogen's current share of such equity financing is approximately US$233 million, but this will be reduced to approximately US$60 million upon completion of the subscription by Energean for additional Energean Israel shares pursuant to the Second EISL Subscription Agreement, with the Group's equity financing commitment in Energean Israel increasing to approximately US$405 million, which will be funded out of the proceeds of the Global Offer. The Senior Credit Facility has a term of 3.75 years and a delayed utilisation structure. Utilisation is subject to satisfaction of a number of conditions, including satisfaction of a projected debt service coverage ratio of 1.5:1, an equity contribution of up to US$465.8 million by the Group and Kerogen, maintenance of a debt to equity ratio of no greater than 66:34, approval of the Karish Lease Environmental Document by the Israeli Petroleum Commissioner and Energean Israel having entered into gas sale and purchase agreements for sales of petroleum from the Karish field to enable Energean Israel to satisfy the aforementioned projected debt service coverage ratio. First utilisation under the Senior Credit Facility is expected to occur no earlier than the fourth quarter of 2018.

Phase 1 expenditure is anticipated to be incurred between the first quarter of 2018 and first gas in 2021 with headline costs incurred as per the table below.

Breakdown of Projected Karish & Tanin Phase 1 Capex and Costs	*(US$ millions)*
Drilling	123
FPSO (Technip EPCIC)	905
Subsea and pipelines (Technip EPCIC)	517
Owners costs	116
Phase 1 contingency	**84**
Contracted deferred payments (Technip EPCIC)[1]	(140)
Capex for Phase 1	**1,605**
Pre-FID costs	60
Lease payments to seller	55
Interest during construction	146
Transaction fees and expenses	60
Total (net of deferred payments)	**1,926**
Contracted deferred payments (Technip EPCIC)[1]	140
Total (incl. deferred payments)	**2,066**

Notes

(1) Deferred payments in respect of the Technip EPCIC Contract represent an amount which Technip has agreed to defer, up to $140 million of the EPCIC costs until 2022 and 2023, to be paid in equal instalments (funded from operating cash flow) out of available cash flows of Phase 1.

The NSAI Israel CPR anticipates capital expenditure for the Karish and Tanin development of US$291.0 million in 2018, US$448.5 million in 2019, US$676.9 million in 2020 and US$208.6 million in 2021.

On 27 August 2017, the Israeli government approved the Karish and Tanin FDP. Energean E&P Holdings and Kerogen have agreed to submit the FID following certain events occurring, including entry into the Senior Credit Facility, entry into the Technip EPCIC Contract and approval of the budget in respect of FID.

A more detailed description of the anticipated Phase 1 timetable is set out below.

Phase 1—expected Karish timetable

Q2 2017	Subsea pre- final investment decision engineering design contract (*completed*)
Q3 2017	Selection of FPSO hull fabrication yard
	Selection of FPSO topside and integration yard
	Approval of FDP by Israeli government (*granted on 27 August 2017*)
	Selection of rig and drilling services contractors
Q4 2017	Completion of full project environmental and social impact assessment and stakeholder engagement plan (*submitted December 2017*)
	Commence Geotechnical, geophysical and environmental base line survey
	Complete geophysical and environmental base line survey work
Q1 2018	Targeted final investment decision
	Complete hull basic engineering and handover to detailed design contractor
	Contract signed with Stena Drilling on 25 January 2018 for the drilling of three wells to begin in Q2 2019, subject to FID by 1 July 2018
	Finalise engineering, procurement, construction, installation and commissioning contract, sign Technip EPCIC Contract
	Sign Senior Credit Facility Agreement
	Complete field geotechnical survey
	Award drilling services contract
	Receive transmission licence from Israeli Minister of Energy
Q2 2018	Submit Karish Lease Environmental Document to Israeli regulator
	Agree INGL asset transfer agreement
Q3 2018	Complete detailed design for topsides and hull
	Issue report on major hazards
	Expected approval of Karish Lease Environmental Document
Q4 2018	Commence fabrication of FPSO hull and topsides
Q1 2019	Mobilise drilling services and start-up logistics operation

Phase 1—expected Karish timetable

Q2 2019	Commence FPSO hull topsides integration and commissioning
	Commence drilling operations
	(first well into Karish Main expected H1 2019, second well H2 2019)
	Complete beach crossing at Dor
Q3 2019	Commence installation of sales gas pipeline, onshore pipeline, DVS and CVS
	Appraisal of Karish D and B Sands
	Commence pipeline installation
Q4 2019	Complete installation of sales gas pipeline
	Transport FPSO hull from China to Singapore
Q1 2020	Complete development drilling
Q2 2020	Install risers, manifolds and SSIV
	Commence commissioning of onshore facilities
	FPSO hull fabrication complete
Q4 2020	FPSO hull towed from Singapore to Israel
	Onshore facilities complete
Q1 2021	Hook up of risers to FPSO
	Practical completion under Technip EPCIC Contract
	Commissioning and start-up of FPSO
	First gas sales
Q2 2021	First oil condensate sales

The Karish main field will be the first asset to be developed in the Karish and Tanin blocks by the Group. Karish was selected as the initial development as it is the largest discovery, is expected to provide the highest yield of liquid per volume of produced gas and is the closest discovery to shore. The assets required to develop this field will be installed and commissioned by early 2021 with the intention of introducing a second source of gas supply into the Israeli market as soon as practicable.

Integrated reservoir, well and facility simulation work has demonstrated that the target gas sales rate of 290 MMscf/day can be delivered initially by a single Karish well. Two wells would be required to produce at the envisaged 400 MMscf/day peak rate. Accordingly three initial wells (the "**Initial Wells**") will be pre-drilled ensuring that a spare well is available. The currently envisaged development plan for Karish and Tanin is that the Initial Wells will be developed between 2019 and 2020 with first gas in the first quarter of 2021. According to the NSAI Israeli CPR, initial production volumes are expected to be approximately 5 BCM/year of gas and 3.2 MMbbls of liquids in 2021, with liquids volumes declining to 3.0 MMbbls in 2027 and declining gradually to 1.4 MMbbls in 2031. Once the Initial Wells water out, the remaining potential of Karish Main B sand will provide approximately three years of additional production. As is discussed in more detail below, the Tanin blocks will be developed so that gas can be produced two years prior to the date on which the Karish main wells are forecast to water out.

A new-build, spread-moored (fixed East-West heading) FPSO, the first to be deployed in the East Mediterranean Sea, will be located immediately south of the Karish field in approximately 1,700m water depth with the Initial Wells tied back to the FPSO. The existing exploration well (Karish-1) will not be re-entered and side tracked. A subsea production manifold will be located immediately south of the well cluster and will include a spare slot for a Karish North discovery well or to enable an additional multi-slot manifold to be accommodated. The Karish Main manifold is designed to allow it to be extended should dedicated Karish Main A and/or B reservoir wells be justified at a later date. The choice of an FPSO as the development option for Karish and Tanin was based on a number of factors. Using an FPSO should result in the development having very low environmental impacts as it avoids bringing liquids close to or on shore it also offers a flexible solution for tying back other small discoveries in the area (either by Energean or third parties). The hull of the FPSO will be new-build but based on an existing design which has previously been classified by DNV-GL and it is anticipated that it will be built in Singapore. The Group believes its planned approach reduces technical execution risks.

In January 2017, Energean appointed TechnipFMC as the concept and front end engineering design ("**FEED**") contractor for the Karish and Tanin development programme. In July 2017, Energean entered into a letter of intent and thereafter, on 19 October 2017, a pre-final investment decision contract with TechnipFMC setting out the terms of the FEED services. On 26 October 2017, 6 November 2017 and 31 January 2018, Energean Israel and TechnipFMC entered variation orders for a combined US$9.7 million and £0.8 million. The variation orders extended the work scope to be performed pre-FID to include all remaining FEED scope, selected detailed design elements (accelerated from the envisaged EPCIC scope) as well as FPSO model testing and (in 2018) early commencement of project management engineering services and procurement that have then been removed from the planned EPCIC scope of services.

In addition to the FEED services, TechnipFMC has also been contracted to construct the subsea, FPSO and facilities work. The Group has agreed the Technip EPCIC Contract, which is a lump sum, turnkey EPCIC contract and covers the majority of the project costs excluding the drilling of the wells. For a description of the EPCIC Contract, see Part 16 "*Additional Information—Material Contracts—Arrangements with TechnipFMC*".

In addition, on 25 January 2018, the Group signed a contract with Stena Drilling to conduct drilling of three development wells at US$140,000 per day, with optional scope for drilling of two near field exploration wells and up to five additional development wells at US$150,000 per day, plus mobilisation up to US$500,000 and demobilisation fuel costs up to US$65,000. See *"Additional Information—Material Contracts—Stena Drilling Contract"*.

The FPSO will process natural gas and hydrocarbon liquids produced from the Karish field and later other nearby discoveries and eventually the fluids from Tanin. Three streams will be created:

- dry gas to INGL pipeline specification;
- a mixed oil/condensate stream stabilised to tanker specification; and
- hydrocarbon-free water.

In parallel with performing technical studies Energean has actively engaged with gas buyers in Israel to determine the potential demand for Karish gas by 2021 and the likely growth in demand following this production start date. Based on this work it has been decided that the integrated production system outlined above will have an initial peak capacity of around 650 MMscf/day. This will allow annual gas sales of 4 BCM/year to be achieved depending on customers' demand profiles.

The production system will have an initial capacity of 6.6 BCM/year of natural gas and 18,000 bopd of oil condensate. Processing facilities will be located on the FPSO deck in a sequence of single or double layered modules and two processing trains, each with a capacity of 400 MMscf/day, will be installed. A single train will be used initially and, once production exceeds 400 MMscf/day, the second train will be used with equal volumes run through both trains. Overall system capacity is initially limited to 650,000 mmscf/day. This could be increased, by addition of a second 16" sales gas riser, to 800,000 mmscf/day – equal to the capacity of the two gas trains running in parallel.

The FPSO is linked to the Israeli coast by a 24" diameter pipeline that expands to 30" 10.9 km from shore. Tie-in points for 3rd party gas supply have been included at this point. The 30" line section passes under the sand dunes at Dor. The development plan is intended to require minimal onshore infrastructure; the dry gas pipeline connecting into the existing INGL pipeline system. The Group anticipates that the construction of this sales gas pipeline will cost approximately US$200 million (which is included in the anticipated overall Phase 1 project costs capex estimate of US$1.6 billion). The Israeli government is expected to contribute up to US$100 million toward the costs of developing the 10.9 km near-shore and onshore sections of the pipeline. Once payment has been received ownership and operatorship of this near-shore section will transfer to INGL. Operation of the pipeline to the INGL system will be managed by Energean through an operations service contract with the Wood Group, with whom Energean has signed a letter of intent and is currently negotiating an agreement.

Energean hopes to sell up to 5 BCM/year of gas during peak production years (as per the NSAI Israeli CPR) and to maintain production until all discovered, commercial resources are produced.

Liquids (approximately API 50) will be offloaded from the FPSO to sales tankers offshore and sold outside of Israel.

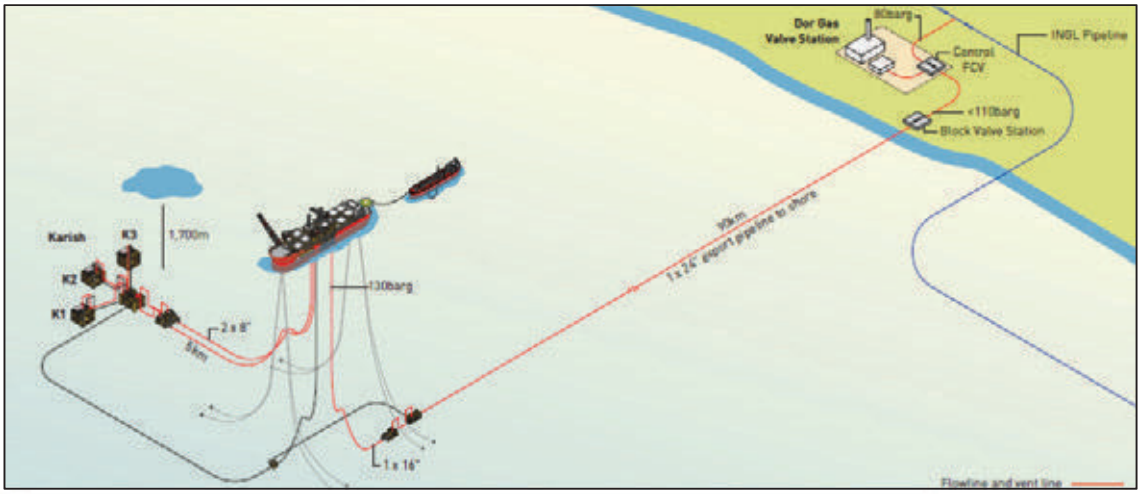
The FPSO will have an oil condensate storage capacity of 800,000 bbls with oil condensate offloaded in parcels of approximately 350,000 to 450,000 bbls to smaller tankers for export to European markets.

The FPSO will also have water processing facilities on board. 100,000bbls of mixed crude/water can be stored on board allowing the water and crude to separate by gravity. Crude will then be extracted from the top and water from the bottom. The water/oil interface will be maintained at a level approximately one third from the bottom. Additional space for 100,000 bbls of produced water undergoing final "polishing" (oil removal) has also been built into the hull. This water can be then recycled back to the process train, can be fed to the oil-centrifuge package or pumped over board if it meets the discharge specification of 15 ppm.

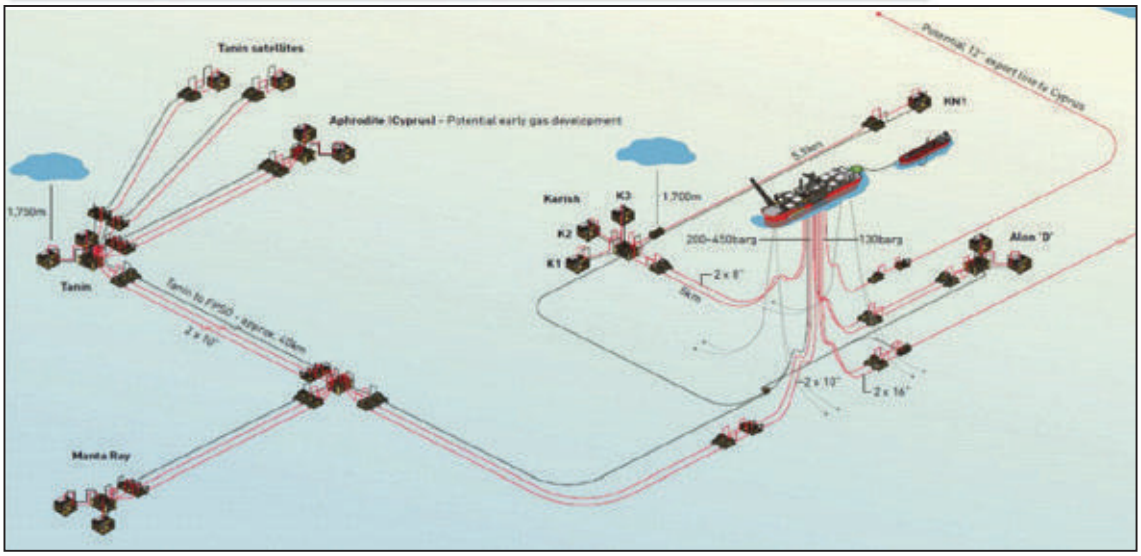
The FPSO is planned to contain simple, modular gas and oil processing facilities and associated utilities. It is planned to generate electricity centrally using gas turbines equipped with Waste Heat Recovery Units. The FPSO has been designed to allow its capacity to be increased with time as the sales market in Israel expands. Specific details are as follows:

- 227m long x 50m wide new build hull;
- tandem offloading for 400,000 bbl liquid parcel size in 24 hours;
- production balcony with provisions for up to eight risers and four umbilicals;
- process area of 1,720m^2 and 4,000 mT with two gas trains (400 mmscfd each) and one oil train (18 kbopd);
- scope for future growth of 1,200m^2 1,200 mT with the ability to take 3,500 mT extra topside expansion for chemical based hydrate management systems and increased oil process capacity;
- utility area of 1,720m^2 and 3,000 with power generation capacity of 45MW and a sea water cooling system; and
- 75 single man cabins will be provided allowing for a maximum POB of 120 (driven by lifeboat capacity) to facilitate maintenance or construction campaign work.

Initial Development Phase



Planned Extension – Ability to Tie Back Marginal Gas Fields in the Region



Due to the fact that the Karish-Tanin FPSO will be located in a complex geopolitical location, enhanced security and defence measures as required by law and under the lease requirements will be taken to ensure its protection. The Group will be responsible for general security measures, in accordance with Israeli Defence Force

guidelines, while responsibility for defence systems lies with the Israeli Defence Forces and will, by law, be led by the Israeli Navy acting as the government regulatory defence entity. Energean has agreed to make available to the Israeli Navy such systems and assistance as are required for the installation of the required defence measures; however, the operation, composition and maintenance of such systems remains the responsibility of the Israeli Defence Forces.

The FPSO will have the technical capabilities on board to conduct maritime and aerial security surveillance and threat detection and will have a rapid response security force capable of eliminating and defending the FPSO from on board and approaching threats. These security measures and processes will be undertaken in combination and cooperation with and under the direction of, the Israeli Navy and Air Force.

Any Energean employees and contractors stationed on the FPSO will have the relevant training to ensure the security of the crew on board and training will be provided on the safety guidelines which are relevant to operations which are conducted when there is an armed forces presence on a civilian producing FPSO.

In addition, the health and safety of the crew stationed on the FPSO will be maintained in accordance with the operational safety guidelines for petroleum and natural gas drilling and production activities published by the Petroleum Commissioner.

The practical completion date under the Technip EPCIC Contract is 31 March 2021. Project handover is scheduled for February 2021 to allow for testing by the practical completion date.

The Directors consider that it is likely that there will be other gas fields discovered in the vicinity of Karish and/or Tanin during the project's lifetime. It is envisaged that these would be relatively small discoveries not able to support a standalone development with dedicated processing facilities and pipeline(s) to shore. Hence the envisaged Karish and Tanin integrated production system has been designed to allow such discoveries to be commercialised via the sub-sea gathering system, FPSO and pipeline to shore. The Directors believe that the FPSO has long-term gas infrastructure potential as a regional hub for third party tie-ins.

Whilst all production from the existing Karish and Tanin discoveries is ear marked for sale in Israel it is possible that additional volumes, or volumes in nearby leases, could enjoy an export quota. At this time it is not possible to assess the potential conditions or likelihood under which Energean might be granted an export quota with respect to the Karish and Tanin discoveries. The FPSO is therefore designed to allow for the installation of two 12" export risers. These could tie into a dry-gas system created on the back of the significant volumes in Noble's Leviathan field, or to serve a smaller market (e.g. Cyprus) that Leviathan gas is unlikely to target. The position of the Karish FPSO makes it well placed to send gas to Cyprus and potentially Turkey.

The NSAI CPR projects that the Karish and Tanin fields will generate positive undiscounted net cash flow from 2021, after deducting payment of the Levy and corporate income taxes. It projects that undiscounted net cash flows will increase to US$708.2 million (of which the Group's 70% working interest, assuming completion under the Second EISL Subscription Agreement, would represent US$495.7 million) in 2023, before gradually declining thereafter. The NSAI CPR projects cumulative undiscounted net free cash flow from the Karish and Tanin fields to be positive from 2023 (from 2024 if applying a 10% discount rate).

Tanin

Overview

The Tanin field is an undeveloped asset in the Levantine Basin and is located north of Israel's EEZ approximately 110km offshore Israel. The water depth is about 1,800m. Tanin is located approximately 40km from the Karish field.

Lease details—Tanin

Area km^2	250
Original grant date	11 August 2014 (lease deeds first granted on 24 December 2015, amended on 25 April 2017)
Expiry	August 2044
Licence type	Tax Royalty

Lease details—Tanin

Main plays	prolific Early –Miocene Tamar Sands play
Number of active wells	0
Partner	Kerogen
Energean Israel's legal interest	100%
Energean's effective working interest:	50%
Data available	3D seismic acquired by Noble in 2009 and data from the Tanin-1 exploration well
Royalties payable	To Delek and Avner (which have since merged together into Delek): 7.5% increasing to 8.25% on the date on which Energean is first required to make payments on account of the Levy, less royalties due under existing royalties for the benefit of other third parties to be paid directly to such third parties. The royalty is calculated on the value of the total amount of gas and condensate produced at the well head without any deduction (except for gas and condensate used in the production process). The royalty is expected to increase to 8.25% in 2024. To the State of Israel: According to Petroleum Law, 5712-1952, a leaseholder is required to pay royalties of 1/8 (12.5%) of the volume of oil produced to the State. The leaseholder will pay the market value of the royalties according to the value of the gas or oil at the well head and not according to selling price to the end customer.
Tax regime	Ordinary corporate income tax rate of 23%. Oil Profits tax (the Levy): According to the Oil Profits taxation law (L.5771-2011), the maximum monthly levy rate, based on the corporate income tax rate from 2018 onwards, may reach up to 46.8%. The proportion of the Levy on the royalties payable to Delek and Avner (which have since merged together into Delek) and other third parties is paid directly by Delek and such third parties or withheld by Energean when paying the royalty and is therefore fully deductible from the cumulative revenue calculation. For more details on the Levy see "*Regulatory Overview—Regulatory and legislative framework in Israel—Fiscal Regulations*".
Hydrocarbons export regime	Permits the production of natural gas and oil condensates only. While the export of natural gas is prohibited, oil condensates are permitted for export. The production and/or export of crude oil would require the amendment of the leases via an addition of a new chapter to the lease by the Petroleum Commissioner. At this time it is not possible to assess the potential conditions or likelihood under which Energean might be granted an export quota.

Lease details—Tanin

Other provisions applicable to Tanin	Permits required for the operation of the production system; local content requirements (lease holder of both leases to invest in local content of no less than US$80 million over eight years); requirements regarding abandoning the production system and plugging wells; bank guarantees to be provided as collateral for fulfilling the terms of the leases and terms for their forfeiture; guidelines for environmental protection, safety, and security; provisions regarding liability, indemnification and insurance.

Reserves and/or resources

Tanin 2C contingent resources have been independently audited by NSAI at 785.9 Bcf for gas and 4.1 MMbbls for liquids. Best estimate unrisked prospective resources have been independently audited at 443.9 Bcf for gas and 39.8 MMbbls for liquids as per the NSAI Israeli CPR.

Field technical background

Tanin forms a northern extension of the Leviathan field that is currently being developed by Noble, Delek and Ratio. The Tanin field was evaluated by Noble in 2011 using the discovery well "**Tanin-1**" which reached a total depth of 5,504m (TVDSS) in what is now referred to as the Tanin-A Block. It discovered gas saturated Tamar A and B sands and proved up gas volumes in the connected Tanin B and Tanin C Blocks. Reservoir properties determined from log and side-wall core data indicate the sands are analogous to those discovered in the Tamar and Leviathan fields.

The Tanin Lease contains, in addition to Blocks A, B and C, significant exploration potential (Blocks D, E and F in the Lease itself and other accumulations that may close outside the Lease area). The field area is covered by the same 3D seismic data as the Karish field. Within the Tanin Lease three additional structures at the Lower Miocene level have been identified from available 3D seismic data. Blocks A, B and C are interpreted to share a common gas water contact at between 5,070 and 5,095m (TVDSS).

The Tanin reservoir is shown in the Tanin-1 well to have similar good quality reservoir sands to those of the adjacent Tamar field (to the south) and Karish field (to the east), with high average porosity of approximately 22% and permeability of approximately 300mD. The reservoir pressure is approximately 610 bar and both temperature and pressure are normal for the reservoir's depth. The Group has generated static and dynamic models to enable future development planning at Tanin.

Field capex plan and outlook

The Group expects to develop the Tanin A, B and C blocks after the Karish field, as described above (see *"—Karish—Field capex plan and outlook"*). The exact date will depend on a number of factors, particularly:

- the quantity of gas sale contracts secured by the Group by 2021 and the growth in gas sales subsequent to this date;
- the confirmed in-place volumes within the Karish field; and
- the timing of exploration activities in and adjacent to the Leases and the results of these activities, particularly the timing of the drilling of the Karish North prospect in the Karish field.

The Group intends the initial Tanin development to consist of two to three wells in the A block tied back via a new manifold and a 40km long multi-phase production system to the Karish FPSO. It is anticipated that the prospects in the NE part of the Karish Lease would be explored/appraised prior to the development of Tanin to ascertain the total volume of resources in the Lease. A full development of the Tanin Lease may require up to eight wells to be drilled. It is currently anticipated that the Tanin prospects might be developed as follows, with exploration wells designed to allow them to be used as development wells:

- A block—three clustered wells with a satellite manifold, twin multi-phase lines (40km) and twin risers. Hydrate management would be by indirect electrical heating;

- C block—two wells with a shared flowline to the Tanin A manifold; and
- B block—with a single remote well with a flowline to the Tanin C flowline.

Tanin would be developed so that gas is ready two years before the point where the Karish C/D sands are depleted. It is planned to measure the reservoir pressure in the B sands whilst draining the C/D sands to assess the contribution of these layers. If volumes are discovered in Karish North and/or Karish East before Tanin is developed, the development of Tanin would be delayed as the successful exploration of Karish North and/or Karish East would provide cheaper incremental development. Tanin could be accelerated if the aquifer at Karish is weaker than envisaged, or the Israeli gas market develops more rapidly. Whenever Tanin is developed it would be tied back to the Karish FPSO. In the case where there is no early Karish B sand production there would be a second drilling campaign to drill Tanin C wells six years after Tanin comes into production. A single well in Tanin B would be expected to be drilled four years later. Production from Tanin is planned to be routed through separate risers to allow production from the two fields to be controlled independently via dedicated chokes at the FPSO inlet. Development of Karish and Tanin Prospects

As described above there are a number of prospects in both the Karish and Tanin fields. The Directors believe that the leads and prospects in the lower Miocene are low risk (POS: 48% to 81% according to the NSAI Israel CPR) as they are generally supported by direct hydrocarbon indicators and are part of the same play that has been successfully leveraged to date in the Levantine Basin. The Directors believe that these upside volumes could be rapidly drilled and matured should either the existing discoveries underperform or should the Israel domestic gas market grow, justifying an increased production plateau rate. The Directors believe that they therefore represent a significant opportunity both with regard to risk reduction and upside value generation.

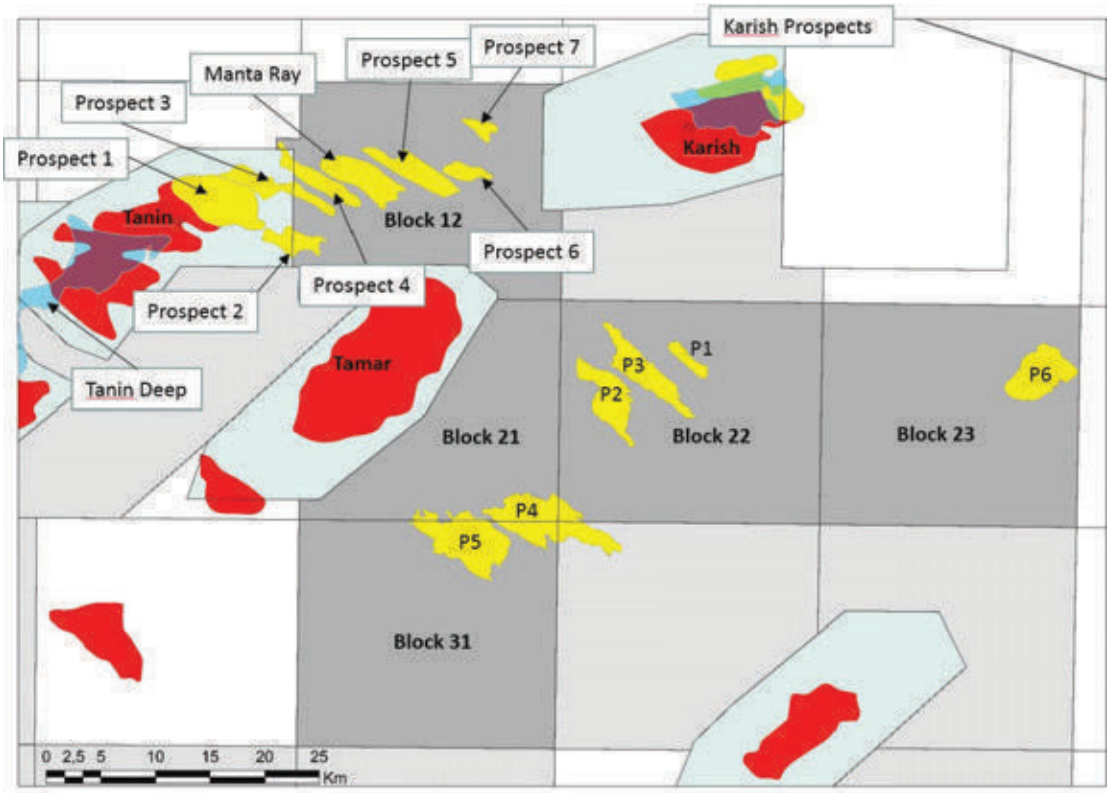
The overall field development plan has therefore been developed making allowance for the eventual discovery and tie-back of future prospects. The Directors believe the FPSO processing capacity will be adequate to process future discovered volumes from recently awarded blocks and potentially generate tolling revenue from future discoveries in neighbouring blocks. The timing of exploration in the Karish and Tanin leases is expected to be reviewed regularly to ensure that risks and upside can be addressed expeditiously.

The most significant individual undiscovered accumulation in the two leases is the Karish North prospect in the Karish Lease (comprising the Northeast Block Prospect, the North Upthrown Block Prospect and the North Downthrown Block Prospect identified in the NSAI Israel CPR). This 3-way structure is located on the northern, down-thrown side of the fault that constrains the Karish Main structure. Karish North's proximity to the Karish FPSO makes it a significantly more attractive second development than Tanin even given the fact it is associated with some, albeit low, exploration risk. Hence Karish North is expected to be drilled at least two years prior to the planned development date of Tanin. In a success case this would allow Karish North to replace Tanin in the development-funnel. A Karish North discovery well could be quickly tied back to the Karish manifold. Risked exploration costs for Karish North are therefore minimal.

The timing of the Tanin development and exploration, as described above, will be driven by considerations including the evolution of the domestic gas market in Israel and the market share that Energean is capable of capturing and the success of the exploration programme within the Karish and Tanin leases and the surrounding areas.

There are also deep prospects identified within both the Karish and Tanin fields. In the Karish block the deep prospect targets prospective Jurassic reservoirs that are interpreted to be approximately 2,000m deeper than the discovered reservoirs in the Karish-1 well with the crest of the structure at approximately 6,100m TVDSS. The last closing contour in the deep prospect at Karish is at approximately 6,660m TVDSS. The Tanin deep prospect targets prospective Cretaceous reservoirs that are interpreted to be 1,500 to 2,000m deeper that the discovered reservoirs in the Tanin-1 well. The crest of the structure lies within the Leviathan Block at a depth of approximately 6,400m TVDSS with the closure defined by a contour at 6,700m giving an areal closure of approximately 800km^2. This structure extends into the Tanin block and the best estimate unrisked prospective resources for the prospect within the Tanin block are 37.8 MMbbls of liquid and 48.3 Bcf of gas (with a probability of geological success of 20%) as per the NSAI Israeli CPR. The Directors expect that an exploration well to test this prospect will be drilled within the Leviathan blocks by 2019. This will provide important information regarding the downdip exploration potential within the Tanin block.

Blocks 12, 21, 22, 23, and 31



In 2017, Energean Israel participated in Israel's First Offshore Bid Round. Energean submitted bids for block 12 (which sits between the Karish and Tanin leases) and four additional adjacent blocks: blocks 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and awards were announced on 12 December 2017, with Energean Israel receiving all five of the additional licences for which it had bid. Each licence has an initial validity period of 3 years, extendable following an application to be submitted by the licensee, no later than 3 months prior to the expiry of the initial period, by an additional 3 year period, subject to committing to drill an exploration well during such period (the drill or drop point) and the conditions of the Petroleum Law.

The original licence data package from the ministry comprised only limited 2D seismic which was insufficient to identify any prospects or leads within four of the five blocks awarded to Energean (Blocks 12, 21, 22, 31). However, as part of the First Offshore Bid Round evaluation, Energean visited the Ministry of Energy office in Jerusalem in order to access and interpret all available 3D seismic data. During this evaluation a number of well-defined attractive prospects were identified that lie within the proven biogenic Tamar sand play fairway (see figure above). The image quality of the 3D seismic is high, so the definition of the prospects is robust, and in some cases seismic amplitude anomalies conformable with structure have been identified which could represent the presence of gas and act as a risk reducer (similar to Karish North). Hydrocarbon reserves for the prospects identified have been carried out internally by Energean, which indicate attractive exploration potential that could be economically developed via a tie back to future infrastructure. A good example is Block 12, which is on trend with the Karish and Tanin discoveries, with several prospects identified on high quality 3D seismic which the Directors believe present an opportunity for low risk exploration which could be developed by a tie back to the FPSO.

The proposed work programs for the blocks include reprocessing existing data available and acquiring new 3D seismic and drilling, subject to certain conditions, drilling an exploration well in block 12.

As part of the bid requirements, the Group paid US$50,000 to acquire a data package prepared for the participants of the bid which contains comprehensive information on the Levant Basin's geology, including regional 2D seismic and well data, and has provided a bid bond for each block of US$0.1 million, valid until 15 July 2018 (extendable by 120 days upon notice from the regulator). Pursuant to the bid documents and the winning announcement made on 12 December 2017, as a condition for the actual receipt of the licences, Energean provided on 11 January 2018 an additional total of US$0.5 million as a signature bonus plus a total of US$6.5 million in bank guarantees as licence bonds to secure its obligations under the licences and a total of approximately US$0.1 million as licence fees. On 15 January 2018, Energean received from the Israeli petroleum commissioner the actual licence deeds for all five blocks it had won. Under the licence, the Group will be obliged

to comply with the work program attached to each licence and estimates that the total capital expenditure regarding the work program for the blocks would be US$7.8 million in the first three years.

6.2 Greece

Regional overview



Greece currently has one oil and gas producing region in the north east of the country. It is in this region that the Prinos basin is located and is where Energean operates Prinos, Prinos North, Epsilon and South Kavala. Prinos and Prinos North are currently the only producing oil assets in Greece. The Group acquired the Prinos basin assets as part of the 2007 acquisition of KOSA. The acquisition was for US$1.5 million (plus acquired indebtedness). At the time of acquisition the Prinos licence was due to expire the following year. An initial extension of five years was granted in 2008 and an extension, by way of an amendment to the licence, of 25 years was granted in 2013 and ratified by the Greek parliament. Subsequently, a new drilling campaign was undertaken in the Prinos basin beginning in the second half of 2013.

Western Greece presents onshore and offshore exploration opportunities. Recently major oil companies have focused their interests on the region including Total, Repsol and Edison. There are also three major pipeline projects contemplated in the region (see "*Overview of Israeli and Greek Oil and Gas Industry—the Greek Oil Industry—Overview—Future pipeline development*").

Prinos

Overview

The Prinos oil field is a producing asset located about 8km west of the island of Thassos and 18km south of the mainland of North Greece. The water depth is about 30m.

Licence details—Prinos

Area km²	6
Expiry	23 November 2024 (with two 5-year extensions, subject to approval)
Licence type	Lease
Main plays	Prinos sands Miocene age
Number of active wells	9 producers and 4 injectors
Partner	N/A
Energean's legal interest	100%
Energean's effective working interest:	100%
Data available	3D seismic data (summer 2015) Geo-cellular model (2017)
Royalties payable	0 to 10% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax. Fixed for the duration of the licence

Reserves and/or resources

Based on the NSAI Prinos CPR, Prinos holds 17.8 MMbbls of 2P oil reserves and 2.9 Bcf of 2P gas and 15.6 MMbbls of 2C oil resources and 4.9 Bcf of 2C gas.

Field technical background

The Prinos field lies within the Prinos basin, formed by large scale north-east to south-west gravity faulting during the Miocene. The Prinos basin was first explored in the 1970s with the Prinos field discovered in 1974 and bought on production in 1981. The initial development of the field took place from 1974 until 1981. For a discussion of the history of the Prinos basin licence please see "*—History and structure of the group*".

The oil produced from the Prinos oil field is an under-saturated sour crude with an API gravity of some 27 to 30 degrees and a high sulphur content. The dissolved gas oil ratio is approximately 675 scf/stb, with a high H_2S content in the gas ranging from 30% to 60%. The solution gas is processed onshore to remove the sour gas. Sulphur is produced as a by-product of the associated gas stream associated with oil production. The amount of sulphur produced varies within each field in the Prinos basin. Each field has a specific gas oil ratio and the liberated gas has different H_2S levels. Export crude from the Prinos basin is a blend of oil from Prinos and Prinos North. In 2017 the average sulphur content of such export crude (as described in the Certificates of Quality and Quantity for each shipment) was 3.41 wt%. Once production commences from Epsilon and Epsilon oil, which has a lower sulphur content than Prinos and Prinos North, is added to the export crude blend it is expected that the blend will have less than 3 wt% sulphur.

A total of 55 wells (including exploration, appraisal, development wells, side-tracks and injectors) have been drilled in the field, of which approximately 12 wells are on production at any time. Water injection was implemented in the field in 1981; four injectors are currently active. Gas lift facilities have been installed and wells are currently gas lifted.

Facilities were installed offshore and onshore to allow up to 27,500 bopd to be produced along with associated gas. Two drilling jackets were installed above the Prinos field, bridge linked to an unmanned offshore processing platform. These offshore facilities were linked by pipeline to shore where a complex gas and oil processing plant was constructed along with oil storage tanks (500,000 bbls capacity) and offshore loading terminal (see below *"—Infrastructure—Sigma Processing Plant"*).

Production peaked at more than 25,000 bopd of moderately sour, 27-30 degrees API gravity oil in 1985 before the onset of decline due to which, the field was temporarily closed in and, in early 1999, was handed back to the Greek State. Production was restarted in late 1999 when KOSA took over the field. In recent years the oil rate decline has moderated. Three new wells commenced production between 2011 and 2015, and three further new wells were completed in 2016 and two in 2017. The average oil production rate in 2016 was 3,190 bopd; a significant increase from the 1,250 bopd in 2015. The field water-cut has decreased from 90% in 2015 to 75% in 2016. However, the first half of 2017 saw a drop in average oil rate to 2,290 bopd with water cut increasing to 81%. The cumulative oil production at 31 December 2017 was 1.02 MMbbls. Water injection performance has been maintained at rates similar to the last two years, averaging 18,000 bopd. Throughout the field's life, oil rates have varied due to near well bore asphaltene, wax and salt precipitation in the wells and completion intervals, prompting frequent treatment with xylene and hot seawater. Asphaltene treatment was a focus of operational activity during 2016. To improve the capability for regular asphaltene treatment of production wells Energean has installed a cantilevered deck space on the Alpha platform. The cantilevered deck allows simultaneous drilling and wire or e-line activities. Wire or e-line operations had in the past only been possible with the drilling rig shut down, which meant significant delays to the drilling schedule. This was installed during and became operational during April 2017 and the introduction of the deck space provided by the cantilevered deck has improved production well uptime and performance as well as reduced the lost drilling time caused by the need to use the drilling rig for non-drilling asphaltene clean-up activities.

Despite these pre-emptive measures taken by Energean, asphaltene problems, coupled with the original dual completion production plan, had a detrimental effect on production in the first half of 2017. In response to this Energean has made two main changes to the well completion and operation strategy which, thus far, appear to be having a positive effect. Firstly, Energean adopted a single string production philosophy with dual completions in recent wells being replaced by single completions. All future wells are intended to be single completions. This allows for the chemical injection to be placed within close proximity of the reservoir intervals under production. Only one well has not been converted to single completion (PA41) and produced from the long and short strings at an average rate of 386 bopd, in 2017, which is viewed as sufficient at this time and so there are no current plans to convert this well. As the well declines and requires interventions to maintain its rate of production the Group may consider a conversion to single completion (which the Directors believe would cost approximately €2.1 million).

Secondly, offtake rates for recent and new wells are being limited to maintain bottom hole pressures at the chemical injection sub of the wells above the asphaltene onset pressure. By operating in this way the Group seeks to ensure that no asphaltene can precipitate ahead of the introduction of chemical treatment to the well stream. Currently two wells are constrained in this way as their water cut is very low. Wells with higher water cut experience fewer issues with asphaltene precipitation and so a production restriction is not necessary in those instances. The Directors consider these steps to be appropriate and, despite delays to the Prinos development plan timetable, long term production and recovery is not expected to be impacted significantly. The Directors believe the asphaltene issues from the first half of 2017 have been resolved and contributed to increased production in the latter part of 2017.

In 2014, Energean modified and adjusted the sour gas treating unit at Prinos. Energean changed the operating parameters and retrayed the DGA stripper tower which led to less steam consumption, and therefore less demand for import gas to generate that steam. Following these modifications the amount of gas required to process each barrel of crude at Prinos fell from about 1.2E+6 Nm^3 per month to 1.0E+6 Nm^3 per month. This led to a reduction in imports from DEPA, the Public Gas Corporation of Greece, from 0.9E+6 Nm^3 per month to 0.65E+6 Nm^3 per month. Assuming a price of DEPA of €0.3/Nm^3, this would reduce operating expenditure by €75,000 per month or €900,000 per year.

Geological and simulation modelling studies undertaken during 2014 and 2015 highlighted potentially significant volumes of un-swept oil across the Prinos field. This was highlighted in the PA34 well. As a result of these studies and well results the Group embarked on infill drilling to take the field to a higher level of recovery.

In 2015 Energean initiated a development plan for the Prinos basin. This development plan is currently anticipated to require an approximately US$353 million to 2021 investment by the Group from 2018 to 2021 (of which approximately US$252 million is for drilling and completion) and approximately US$65 million from 2021 to 2034. Under this development plan, the Group has spent US$173.3 million from 2015 to 31 October 2017 (see note 6 in Section B of Part 13: *"Consolidated Historical Financial Information*"). This investment will be funded by a combination of borrowings under the RBL Senior Facility Agreement and the revenues generated by sales under the BP Offtake Agreement. The amount spent to date includes the acquisition and refurbishment of Energean Force and has, and will continue to, finance the drilling programme.

With the completion of the first four infill wells under the development plan (PA-35A, PA-40, PA-36 and PA-41), peak production rates in 2016 exceeded 4,500 bopd of medium grade sour oil plus associated gas. During the first half of 2017 infill wells PA-38 and PA-33 commenced production and a workover of well PA-40 was completed. PA-37 was completed in December 2017. During the 2018 through 2019, a total of eight development infill wells are planned to be drilled plus three work-overs. Prinos produced at rate of approximately 2,576 bopd in the year ended 31 December 2017 (2,709 bopd excluding 18 days of scheduled maintenance during which the plant was shut down).

All facilities, off- and on-shore at Prinos are owned by the Greek State and exclusively leased to Energean through a concession agreement. Under the concession agreement, abandonment of the productive wells and 'historic' infrastructure facilities (i.e. those delivered to the initial concessionaire in 1999) is the responsibility of the Greek State. Energean is under no obligation to return that infrastructure to its original (1999) condition. Energean is however responsible for the rehabilitation of new wells drilled after the grant of the lease (as of 31 December 2017 this related to up to 13 wells drilled by Energean). The concession agreement has been ratified by law in Greece and enjoys a tax and fiscal regime which is different to the generally applicable Greek law, specifically in relation to the applicable special income tax rate and granting several exemptions on stamp duties, indirect taxes and ordinary or extraordinary contributions. Where special tax provisions are applicable the Prinos concession agreement prevails.

The NSAI Prinos CPR demonstrates the abandonment liability in relation to the Prinos basin fields. Costs of US$31.6 million in the proved (1P) case and US$ 32.6 million in the proved plus probable (2P) and proved plus probable plus possible (3P) cases are included for abandonment of the platforms, wells and production facilities at the economic limit of the field. These costs are the net costs to Energean. Energean is responsible for 50% of the abandonment costs and the Greek State is responsible for the remaining 50%.

Operational outlook

Although the Prinos basin licence does not mandate the drilling of additional exploration wells or capital expenditures and the Prinos field is mature, the Directors consider that there is scope for extracting additional value from the area by increasing production through:

- infill drilling and side-tracks to target bypassed oil;

- recompletion and/or additional perforating of existing wells on un-drained sands;
- optimisation of the distribution of gas lift gas;
- optimisation of water injection for pressure support and improved reservoir sweep;
- installation of jet pumps in wells with low reservoir pressures; and
- deep downhole chemical injection to minimise asphaltene precipitation.

Prinos North

Overview

The Prinos North field is a producing asset and is one of the satellite fields within the Prinos basin located approximately 3km north of the Prinos field and 18km south-west of the mainland of Northern Greece. The water depth is about 38m.

Licence details—Prinos North

Area km^2	1.5
Expiry	23 November 2024+5+5 years extension subject to approval
Licence type	Lease
Main plays	Prinos sands Miocene age
Number of active wells	1 horizontal producer
Partner	N/A
Energean's legal interest	100%
Energean's effective working interest:	100%
Data available	3D seismic data (2015) Geo-cellular model (2017)
Royalties payable	0 to 10% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax. Fixed for the duration of the licence

Reserves and/or resources

Prinos North 2P reserves have been independently audited by NSAI at 3.3 MMbbls of oil and 0.3 Bcf of 2P gas.

Field technical background

The Prinos North structure was initially identified as a potential exploration opportunity in 1976, when the Prinos-4 (P-4) delineation well encountered small quantities of oil to the north of the Prinos oil field. This led to the acquisition of 3D seismic data in 1993 and the drilling of Prinos North-2 (PN-2) exploration well in 1994, which discovered the main field, as well as a second deeper and thinner sandstone reservoir, called the Delta prospect. For a discussion of the history of the Prinos basin licence please see "*—History and structure of the group*".

The Prinos North field contains moderate-heavy (21 degrees API gravity), under saturated, sulphurous crude oil and associated H_2S rich gas. Prinos North was appraised and developed as a satellite field to Prinos by an extended reach horizontal well, PNA-H1, in 1996. In 1996, PNA-H1 was brought in production and produced until 2004 with a peak rate of almost 3,000 bopd of approximately 21 degrees API sour oil in 1997 before declining.

The field was shut-in in 1999 for a year due to low production and low oil prices and was handed back to the Greek State by the original operator. Production restarted in late 1999 until 2004 when the well was closed-in because of a high water cut. An attempt was made in June 2004 to side-track the well to a structurally higher position in the field, Well PNA-H2, but drilling was unsuccessful and the well was plugged and suspended. The well was successfully side-tracked for a second time as Well PNA-H3 and production from the field was successfully reinstated in late July 2009.

After some technical interventions, the average oil production rate was 330 bopd in 2016 and subsequently declined to 227 bopd in 2017 (239 bopd excluding 18 days of scheduled maintenance during which the plant was shut down) at a water cut of some 78% to 80%. The cumulative annual oil production in Prinos North at 31 December 2017 was 82,880 bbls.

Field capex plan and outlook

Energean plans to keep the PNA-H3 well slot in production and to drill an extended reach horizontal well, PNA-H4 from an alternative slot. This is expected to drain attic oil that is mapped in an up-dip location to the west of Well PNA-H3. This new development well is expected to cost US$8 million and is expected to increase production from Prinos North which, as per the NSAI Prinos CPR, is expected to peak at 861 bopd in 2019 from the current 200-300 bopd.

See "*—Field development for the Prinos basin*" for more details on future developments within the Prinos basin.

Epsilon

Overview

The Epsilon field is an undeveloped asset, is one of the satellite fields within the Prinos basin and is located approximately 3km west northwest of the Prinos oil field. The water depth over the field is about 35 to 45m.

Licence details—Epsilon

Area km^2	4
Expiry	18 June 2029 +5+5 years extension subject to approval
Licence type	Lease
Main plays	Prinos sands Miocene age
Number of active wells	0
Partner	N/A
Energean's legal interest	100%
Energean's effective working interest:	100%
Data available	3D seismic survey (2015) 3D and Bathymetry survey (2015) Geo-cellular model (2017)
Royalties payable	0 to 10% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax. Fixed for the duration of the licence

Reserves and/or resources

Based on the NSAI Prinos CPR, Epsilon holds 18.4 MMbbls of 2P oil reserves and 2.8 Bcf of 2P gas and 0.1 MMbbls of 2C oil resources.

Field technical background

Exploration activity in the Epsilon field area began in the 1990s, when the anticlinic Epsilon structure was identified by the interpretation of 2D seismic data. The area remained a low priority, and was only partially covered by a 1993 3D seismic cube survey. The 3D seismic survey acquired in 1997 however, covered the whole area, and made it possible to map the structure, and consequently upgrade Epsilon as a high priority exploration target.

The field was discovered in 2000 when the well E-1 tested sour crude oil with an API gravity of 36 degrees at a depth of about 2,800m (TVDSS). This well was side-tracked (E-1AS) a year later (in 2002) to a location some 500m to the south east, confirming the reservoir presence and tested oil.

The known Epsilon reservoir is characterised as multi-layered, since it is subdivided into thinner layers, which are believed to extend through the whole field. The reservoir is composed of 3 main pay layers, L1, L2, L3 and an additional L4 sandstone found only on one well.

The oil at Epsilon is sour with a gravity of approximately 36 degrees API. The H_2S content in the separator gas samples reaches 14.37%.

Energean drilled an extended reach multi-lateral well, EA-H1, from the Alpha platform which was successfully completed in January 2010 and produced for a 12 month period with an initial oil rate of over 2,000 bopd under natural flow. The measured depth of the well reached 5,297m and was, when completed, the well with the greatest measured depth in the Mediterranean. In order to accelerate production from EA-H1, Energean made the decision to utilise artificial lift which, as a result of a fault in the design of the well, led to the collapse of the well casing in the EA-H1 well. This collapse was discovered during a workover undertaken in February 2011. As a

result of this collapse, the oil rate had declined to under 400 bopd in late 2010 and the cumulative oil production was just over 0.33 MMbbls. Attempts to side-track the well in 2011 were unsuccessful due to repeated stuck pipe and it was plugged and abandoned.

The further development of the Epsilon satellite following the casing collapse in EA-H1 considered two options, the twining of the original ERC well EA-H1 to accelerate data and production or the placement of a new platform over this satellite accumulation and its development. The latter option has been chosen with 3 predrills being installed ahead of the platform installation to allow for data acquisition and early production once the Lambda platform is installed. The Jupiter jackup rig has been retained to drill these three wells, which will be suspended ahead of the platform installation detailed below.

A geophysical campaign took place in the third quarter of 2015 as part of the Epsilon development project. Production is targeted to restart at the Epsilon field in August 2019.

Field capex plan and outlook

The development plan for Epsilon will shortly start to be implemented, having secured funding resources under the RBL Senior Facility Agreement and signed the GSP EPCIC Contract. The intention is to place a minimum of facilities, namely an unmanned platform, in the field with oil, water injection and gas lift pipelines tied back to the Prinos platform. All fluids processing will occur at the Prinos platform. Energean plans to develop the field through a new development project which consists of:

- The drilling of three template wells expected to be drilled in the second quarter of 2018 for data acquisition and early platform production once the platform is installed, i.e. 3 wells producing at a cumulative rate of ~3000 bbls/d. Two to four additional wells are expected to be drilled in the second half of 2019.
- The design, fabrication, installation, commissioning and subsequent operation of a new well-head jacket platform (called "**Lamda**") approximately 3.5km's north west of the existing Prinos platforms. Lamda has been designed to be normally unmanned. Lamda is currently expected to be installed during the second or third quarter of 2018 and will be tied back to the existing onshore and offshore facilities at Prinos.
- The installation of three sub-marine pipelines that connect Lamda to Prinos Delta.
- Drilling is planned to start on the development of the Epsilon field by the second quarter of 2019 with the exact number of wells to be based on an assessment of the in place volumes derived from the early static and production data.

As per the NSAI Prinos CPR, the Group anticipates that the Epsilon development plan requires an additional US$61.6 million investment (for the facilities construction costs, excluding drilling costs) with first oil targeted in the first half of 2019 and production from the Epsilon field expected to peak at 5,324 bbls per day in 2020.

On 8 December 2017, Energean signed an US$88.3 million lump sum turnkey EPCIC contract with GSP Offshore S.R.L ("**GSP**") for construction of the Lamda platform and the drilling of three wells. See *"Additional Information—Material Contracts—GSP EPCIC Contract"*.

Pursuant to Law 4014/2011, an environmental impact assessment ("EIA") has been prepared in respect of Epsilon. As agreed with Greek authorities, this will also cover the operation of the existing facilities in the Prinos offshore area since the operations of the new and old offshore facilities will be operationally interlinked. The Prinos onshore facilities are covered by a detailed EIA, which was renewed and reapproved by the Greek authorities in 2013, (213450/5/12/2013, General Secretariat of Environment, YPEKA — currently YPEN). The existing offshore facilities are also covered by an EIA, which was renewed and reapproved by the Greek authorities in 2013 (46781/12/8/2013). The EIA also takes into consideration the EBRD's environmental and social requirements, which include a full environmental and social impact assessment ("ESIA") and disclosure thereof for a minimum of 60 days prior to a financing decision. The Group has produced an ESIA that serves both purposes. The ESIA was submitted to the ministry on May 2015 and the Decision on Approval of Environmental Conditions is in the final stage of being issued.

South Kavala

Overview

The South Kavala gas field is a developed asset which produces only intermittently. South Kavala was the first hydrocarbon reservoir discovered in the Prinos basin and is located approximately 11km south of the Prinos oil field. The water depth is about 58m.

Licence details—South Kavala

Area km2	4
Expiry	November 2018
Licence type	Lease
Main plays	Sandstone reservoirs sealed by Messinian evaporates
Number of active wells	2
Partner	N/A
Energean's legal interest	100%
Energean's effective working interest:	100%

Field technical background

The South Kavala field covers an area of approximately 4km^2, is formed by a four way dip closed anticlinal structure and contains sweet gas, with more than 80% methane. South Kavala was discovered by the drilling of the SK-1 well in 1972. The field was developed in parallel to Prinos as a remote satellite during the period between 1979 and 1980 and started delivering gas in 1981 to the Prinos facilities and to the onshore Sigma plant and for sale. Two producing wells have been active since then, with an average total depth of 2,050m.

The field has been producing since 1981 and has produced more than 850 million m³ of gas. Due to the depleting reservoir pressure gas production cannot be continuous but in repeated cycles of about 25 days (10 days production and 15 days shut-in phase) to allow the wells to build up pressure. When Energean is producing sufficient gas to meet its production requirements, and is therefore importing gas at a rate of less than 7000 Nm^3/d, there is no production from South Kavala as the Kappa platform booster compressors require a higher rate than 7000Nm^3/d in order to operate. The gas production rates are currently at 400—700 Nm^3/h. The Group currently uses the gas produced from this field for its own internal operations.

Operational outlook

In November 2015, Energean was awarded a 3-year (2+1) extension in the duration of South Kavala licence and has been preparing a new development plan for the period 2017-2019 that will cost approximately US$ 1.5 million. The gas produced is used as a power generation source for Energean's producing Prinos platform complex.

The project is under evaluation and includes the installation of down-hole pumps in two of the existing wells to remove liquids from the well bores which will enable the field to be placed back into continuous production, increase condensate yields and bring recovery eventually up to 98.5%.

The South Kavala gas field is considered an attractive candidate for an underground gas storage ("**UGS**") due to the potential use of the existing infrastructure, its technical characteristics and its strategic location with regard to the stability of the country and region's energy supply. Greece imports the majority of the gas it uses and Energean believes could benefit from the greater security of gas reserves. The UGS could also be linked to the Trans-Adriatic Pipeline that will transit Greece approximately 2km from Energean's onshore processing plant.

In 2011, the rights of the Hellenic Republic for the usage, development and commercial exploitation of a natural gas storage facility in the nearly depleted offshore natural gas field in South Kavala were transferred to the Hellenic Republic Asset Development Fund (with the Group retaining the rights to operate and develop South Kavala as a gas field). The project would consist of the conversion of the depleted South Kavala field to a UGS.

Preliminary studies identified two potential UGS designs that focused on delivering gas for either peak or seasonal demand. The design constraints of these concepts were assessed, with the peak demand scenario offering a maximised flow rate without any plant constraints downstream of the wells and with a working gas volume of 1,060 MCM per year, delivered in two cycles of 530 MCM at a maximum deliverability of 9 MCM/day and maximum injection rate of 7.5 MCM/day, while the seasonal demand scenario sees the facilities constraining the wells and having a working gas volume of 685 MCM per year and just one cycle, in which the maximum deliverability is 6.5MCM/day and the maximum injection rate 5.0 MCM/day.

Energean is considering pursuing the conversion of South Kavala to a UGS, and the Directors intend to participate should a bid round or tender process for such conversion be launched by the Hellenic Republic Asset Development Fund. A capital expenditure estimate of approximately US$400 million was estimated for this conversion in 2010, when oil price was driving contract and unit prices, but this estimate has not been updated. The cost of any future conversion is still being evaluated and could be more or less than this amount.

Katakolo

Overview

The Katakolo oil field is an undeveloped asset located within the West Katakolon offshore field about 3.5km off the Cape of Katakolon. The water depth is over 300m.

Licence details—Katakolo

Area km^2	545, of which 59 designated for exploitation
Expiry	26 August 2041
Licence type	25 year Exploitation Licence (with two five-year extension options)—60km^2 area.
Main plays	Fractured carbonate reservoir
Number of active wells	0
Partner	N/A
Energean's legal interest	100%
Energean's effective working interest:	100%
Data available	3D seismic survey (1984, reprocessed in 2016)
Royalties payable	2 to 20% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax

Reserves and/or resources

Based on the NSAI Katakolo CPR, Katakolo holds 10.5 MMbbls of 2P oil reserves and 6.2 Bcf of 2C gas resources.

Field technical background

Katakolo was discovered by the Greek State Oil company just off the coast of Peloponnese in the Ionian Sea in 1981 through the drilling of the West Katakolo-1 well. West Katakolo-1 was followed by West Katakolo-1A and South Katakolo-1 wells, which found oil. A second well (West Katakolo-2) in 1982 tested oil from two zones with flow rates 1,200 – 1,400 bopd. The oil gravity is 26 – 28 API. In the same year, the South Katakolo-1A well found gas shows from the Triassic breccia. A 3D seismic survey was acquired in 1984 and there was thereafter no activity until 30 years later, when Energean was awarded the block. The West Katakolo reservoir is believed to be a dual porosity system (matrix, fractures and vugs), with an overlaying gas cap and an underlying aquifer.

Energean has been exploring the block since October 2014, after the ratification by the Greek Parliament of the Lease Agreement signed with the Greek State on 14 May 2014. Energean declared commerciality for the field after having finalised the reprocessing and interpretation of the existing 3D seismic data.

Operational outlook

A strategic environmental impact assessment was approved by ministerial decree in August 2013, and published on the official website of the Ministry of Energy before the Lease Agreement was signed with the Greek State on 14 May 2014.

Throughout the first exploration phase, environmental baseline reports were approved in August 2015 and February 2016. In June 2016, an archaeological permit was approved for the drilling site and production facilities to be situated in Dafnouli Municipality of Pyrgos in June 2016. Energean's FDP, including an environmental scoping report, for the Katakolo field was approved in September 2017 after an application was submitted in February of the same year. In 2015, an area within the block was classified as public forest land for use in future development. An Environmental and Social Impact Assessment, including an application for authorization of production facilities on the designated public forest land, will be submitted for approval in 2018. Upon approval, the Company intends to take a FID on the project, expected in the second half of 2018, and drill the first pilot hole to be converted to an injection well in the second half of 2019, with first oil expected in 2020. The development plan for Katakolo has a capital expenditure budget of US$97.2 million to 2036 (US$83.9 million to 2021).

Energean will use extended reach drilling technology to drill from onshore to offshore reservoirs, in a similar manner to several wells Energean has drilled in Prinos. The programme includes also the building of roads and the installation of the necessary facilities including storage deposits and a buoy.

Ioannina

Overview

Ioannina is an onshore exploration asset located in the Ionian Zone, which the Directors believe includes a number of leads, including the Raeko lead described in the NSAI CPR.

In March 2017, Energean agreed to farm out a 60% working interest and operatorship of Ioannina to Repsol.

Licence details—Ioannina

Area km^2	4,187
Expiry	2019—October (first exploration phase)
Licence type	Lease
Main plays	fold thrust belt with multiple play concepts (shallow and deep exploration targets identified)
Number of active wells	0
Partner	Repsol (60%)
Energean's legal interest	40%
Energean's effective working interest:	40%
Data available	Full-tensor gravity ("**FTG**") survey (2015) Legacy of vintage 2D seismic
Royalties payable	2 to 20% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax

Reserves and/or resources

Based on the NSAI Ioannina and Montenegro CPR, Ioannina holds best estimate unrisked prospective resources of 103.3 Bcf for natural gas and 187.1 MMbbls for liquids.

Field technical background

The previously Greek state owned public petroleum company drilled eight exploration wells in the 1980s which encountered oil and gas shows throughout the Mesozoic section, as well as drilling thick sections of high quality potential source rocks in the Cretaceous, Jurassic, and Triassic. 1,000km of legacy seismic lines (2D) data which cover Ioannina have been acquired to date. The last concession holder was Enterprise Oil, which relinquished the block in 2001 after the unsuccessful drilling of the exploration well "Dimitra". Based on Energean's evaluation of data provided by HHRM, 11 exploration wells have been drilled in the block using limited or no seismic data. Only two wells drilled the primary carbonate reservoir target beneath flysch in the 1980s and both were drilled off structure.

All of the dry holes have been drilled on inadequate data, in terms of quantity and quality, for this complicated subsurface environment, and consequently, are unlikely to have tested valid traps. Energean has been exploring the block since October 2014, after the ratification by the Greek Parliament of the Lease Agreement signed with the Greek State on 14 May 2014.

Western Greece is part of the same petroleum system(s), commonly referred to as the Ionian Zone. On a regional scale, the area may also be considered to be the southern-most extension of the greater Adriatic Basin, which has been proven productive for oil and gas in Albania, Italy, and Croatia. There are working analogues between Ioannina and Albania and Italy. In particular, the recent oil discoveries by Shell from onshore Albania lie directly on the same geological trend with leads identified within the Ioannina block. Energean geologists have observed numerous live oil seeps in the field during geological field work studies in the last two to three years and have identified multiple leads using reprocessed legacy seismic. Ioannina is located approximately 120km from the Albanian Shpirag discovery, operated by Shell, where three wells have been drilled on the structure to date. Shpirag is a light oil discovery with a reported oil column of approximately 800m. The regional structural lineaments identified at Shpirag extend into the Ioannina block and similar structures and fractured carbonate reservoirs are identified from surface geology outcrops. Multiple play concepts are recognised within the Ioannina block, with both shallow and deep exploration targets identified.

Operational outlook

Ioannina is currently in the first exploration phase of the exploration period, in respect of which it had an initial €7.9 million commitment (reduced to €5.6 million as of 31 October 2017), which is sequentially reduced according to the implementation of the minimum work programme. The second and third exploration periods (running until 2023) have a total commitment of approximately €23 million.

The interpretation of the FTG data for Ioannina was completed in 2017 and 2D seismic reprocessing in 2016. Geological surveys have been carried out with final reports now available and complementary studies underway. 2D seismic will be acquired comprising 400km in length. The acquisition has commenced with a test line in 2017 and the main survey in 2018, at an expected cost of US$20 million. A decision as to whether to enter into the next exploration phase is expected by October 2019.

The first stage of the environmental baseline report ("**EBR**") which covered the whole Ioannina block was submitted in January 2015 and approved by the Greek Ministry of Environment and Energy. The second stage EBR, which focuses on the areas within the Ioannina block where seismic is to be acquired, was submitted in March 2017 and approved by a positive opinion of the Greek Ministry of Environment and Energy issued on 6 June 2017. The environmental action plan was submitted to HHRM on 27 June 2017 and was approved by the Environmental Licence Directorate on 17 October 2017. In December 2017, Repsol began seismic evaluation at Ioannina.

Aitoloakarnania

Overview

Aitoloakarnania is an exploration asset located in the Ionian Zone.

In March 2017, Energean agreed to farm out a 60% working interest and operatorship of Aitoloakarnania to Repsol. In May 2017, Energean signed the lease agreement in respect of Aitoloakarnania. The lease was ratified by the Hellenic Republic Parliament on 28 February 2018.

Licence details—Aitoloakarnania

Area km^2	4,360
Expiry	2020 (first exploration phase)
Licence type	Tax Royalty
Main plays	Fold thrust belt with multiple play concepts (shallow and deep exploration targets identified)
Number of active wells	0
Partner	Repsol (60%)[(1)]
Energean's legal interest	40%[(1)]
Energean's effective working interest:	40%[(1)]
Data available	Vintage 2D seismic
Royalties payable	4 to 20% based on a sliding scale of average daily production
Tax regime	20% income tax and 5% regional tax

Notes:

(1) The legal and working interest shown here are subject to completion of the Repsol farm-out agreement. Prior to this completion, Energean remains the 100% holder of the asset.

Field technical background

In the early 2000s, Triton held the Aitoloakarnania lease and drilled wells which were too shallow, as they were drilled to commitment depths only. There is a very large area of evaporite outcrops which indicate sub-evaporite targets, while the Ionian Zone carbonates thrust potential is also recognised. Energean acquired the block in May 2017 and the lease was ratified by the Greek government in the plenary sitting convened for 28 February 2018.

Aitoloakarnania is part of the same Ionian Zone as the Ioannina field. A description of that area is included in "*—Overview of assets—Greece—Ioannina*" above.

Operational outlook

There are currently three exploration phases of the exploration period of up to seven years with total commitments of approximately €27 million (of which €7.2 million are to be incurred during the first three year exploration phase). Commitments during the first exploration phase include: obtaining an environmental baseline report, seismic reprocessing, geological, geo chemical and geophysical surveys, FTG gradiometry and aeromagnetic surveys and new seismic acquisition.

Seismic is expected to be acquired in 2019 at an estimated cost of US$20 million to define drillable prospects and a decision as to whether to enter the next exploration phase is expected in 2020. The Directors anticipate that Aitoloakarnania will be developed as a four-well development.

Farm-out to Repsol in respect of Ioannina and Aitoloakarnania

The Group has entered into farm-out agreements with Repsol in respect of the Ioannina and Aitoloakarnania assets (the "**Repsol Farm-Out Agreements**"). Under the Repsol Farm-Out Agreements, the Group agrees to transfer and assign 60% of its interest in the Ioannina and Aitoloakarnania assets to Repsol and Repsol agrees to accept such transfer and assignment. The Group retains the remaining 40% interest in the assets. The Repsol Farm-Out Agreements are governed by English Law.

The Repsol Farm-Out Agreements commenced on 31 March 2017 and govern the relationship between the parties until completion (which is to occur after the satisfaction of the conditions precedent under the Repsol Farm-Out Agreements including the prior written consent of the Greek State, as represented by the Greek Ministry of Energy, and, in any event, not later than one year after the date of such agreements), at which point the rights and obligations of the Group under the lease agreements for the Ioannina and Aitoloakarnania assets will be transferred to Repsol and joint operating agreements ("**Repsol JOAs**") will be entered into between Repsol and the Group. From that point Repsol will assume all obligations as a co-lessee and as the operator under the Ioannina and Aitoloakarnania lease agreements and the Repsol JOAs and Repsol shall be entitled to 60% of the rights and benefits relating thereto.

The costs of certain works (for example the acquisition of seismic data), as well as the geological and geophysical and the general and administrative costs, related to the work programme to be implemented during the first exploration phase at Ioannina and Aitoloakarnania are allocated between Repsol and the Group. Repsol assumes 90% of such costs, up to a pre-agreed maximum cap of US$49.9 million, with the Group paying the remaining 10%. If and when such maximum caps are exceeded, additional amounts due in respect of these specified works are paid by the parties in accordance to their participating interest (60% by Repsol and 40% by the Group).

The Repsol JOAs are to be negotiated and entered into on or upon the completion of the relevant Repsol Farm-Out Agreement. They will be based on the 2012 "International Joint Operating Agreement" model published by the Association of International Petroleum Negotiators. The Repsol JOAs will have effect from their effective dates until (a) the lease agreement for the relevant asset (Ioannina or Aitoloakarnania) terminates, (b) all materials, equipment and personal property acquired for or used in connection with operations have been disposed of or removed and (c) final settlement has been made. Subject to approval by the Greek government, Repsol is to be designated as the operator of the Ioannina and Aitoloakarnania assets under the Repsol JOAs, and assumes the rights, functions and duties of the operator as set out in the lease agreements. The Group will provide Repsol with certain technical and administrative assistance regarding interaction and relations with the Greek government, local communities and stakeholders during petroleum operations.

If a party to the Repsol JOAs wishes to withdraw they must (a) be in compliance with their contractual obligations and (b) have completed all minimum work programme requirements. On withdrawal, the withdrawing party remains liable for its share of expenditures under any annual work programme and budget approved prior to the date of withdrawal. The interest of the withdrawing party shall be assigned to the remaining parties (subject to approval by the Greek government).

6.3 Montenegro

Regional overview

The earliest records indicating oil in Montenegro are from 1865 with the first well drilled in 1922. After WWII, exploration activity took place from 1949 to 1966 which resulted in the drilling of 16 onshore exploration wells by the Montenegro state company Nafta Crne Gore. In 1973, the responsibility for the exploration of hydrocarbons in Montenegro was taken over by the government-owned Jugopetrol Kotor which, in cooperation with foreign oil companies, acquired over 10,000km of 2D seismic data and 400km^2 of 3D seismic data in the offshore region. In addition approximately 1,250km of onshore 2D seismic data was also acquired.

Three offshore and one nearshore wells were drilled between 1975 and 1991. The JJ-1 well (4,700m) encountered several hundred feet of potential gas pay within the Tertiary sequence. The subsequently drilled JJ-3 well had good oil shows within the Eocene and the Cretaceous sequences.

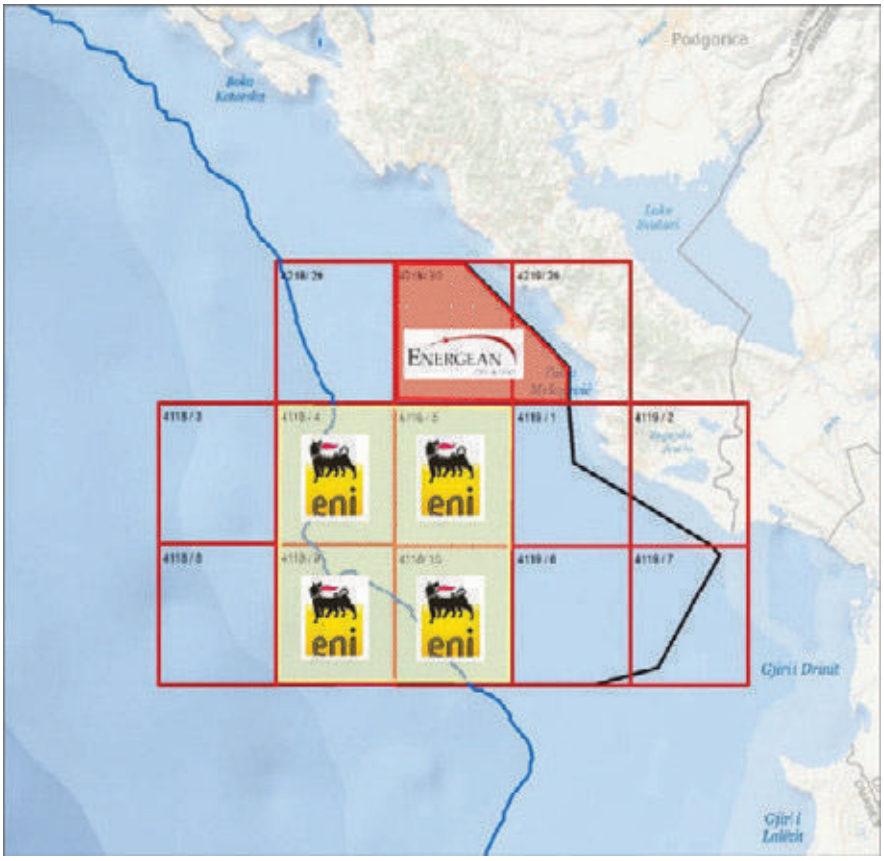
The widespread distribution of seeps and oil shows in the region indicates the presence of an active petroleum system. Direct hydrocarbon indications are interpreted on the marine seismic data in offshore Montenegro with bright event, positive AVO effects and gas chimneys in several zone within the Oligocene, Pliocene and Pleistocene sequences.

In addition to the carbonate oil play, offshore wells have found gas-bearing sandstones and conglomerates which are thought to be involved in both stratigraphic and combination traps. Future 3D seismic acquisition will be key in identifying and drilling the most attractive prospects in order to unlock the true potential of this play.

In May 2014, Energean submitted a bid in the context of Montenegro's First Round for Production Concession Contracts for offshore hydrocarbons exploration and exploitation. Energean reached an agreement with the Ministry of Economy of Montenegro in June 2016 and the agreement was ratified by the Montenegrin parliament in December 2016. The eastern Adriatic remains substantially underexplored, despite having what appears to be all the necessary hydrocarbon generating components in place and the fact that the western offshore Adriatic has been a prolific hydrocarbon producing province for over 50 years for both oil and biogenic gas (with both Albania and Italy producing from fields with appear analogous to the plays identified offshore Montenegro).

Blocks 30 and 26

Overview



Blocks 30 and 26 are adjacent offshore exploration assets located close to the Montenegrin coast at water depths of between 5m and 75m.

In March 2017, Energean signed a Concession Agreement with the State of Montenegro for hydrocarbon exploration and exploitation of the two blocks.

Licence details—Blocks 30 and 26

Area km^2	275 for Block 30 63 for Block 26
Expiry	2020 (first exploration phase)
Licence type	Tax Royalty
Main plays	Tertiary biogenic gas and thrusted carbonate structures (Cretaceous age)
Number of active wells	0
Partner	N/A
Energean's legal interest	100%(1)
Energean's effective working interest:	100%(1)
Data available	3D Seismic (2003), 2D seismic
Royalties payable	5% to 12% for liquid hydrocarbons based on a sliding scale of production 2% for gas
Tax regime	54% Corporate Tax

Notes:

(1) Under the terms of the licence Energean is obliged to bring in two additional concessionaires (to hold at least a 41% interest) for the development of blocks 26 and 30. Energean has discretion as to operating the assets. The Group is awaiting the results of the 3D seismic acquisition, expected to be carried out in 2018, to determine which form of participation (sole operator, joint operator, non-operating interest) from additional concessionaires would be most suitable for these assets.

Reserves and/or resources

Based on the NSAI Ioannina and Montenegro CPR, Blocks 30 and 26 hold best estimate unrisked prospective resources of 1.8 Tcf of natural gas (0.9 Tcf in prospects, 0.9 Tcf in leads) and 143.9 MMbbls for liquids (3.8 MMbbls in prospects, 140.1 MMbbls in leads).

Exploration technical background

Blocks 30 and 26 were officially awarded to Energean in March 2017. The blocks have a surface area of 338km^2 and sit in water depths of 5 to 75m. Cretaceous carbonates represent the main reservoir target with secondary gas targets within sandstone reservoirs of the Pliocene and Oligocene age.

The Pliocene gas targets are well imaged on the current seismic data and are associated with prominent amplitude anomalies. Several prospects have been identified and evaluated in the NSAI Ioannina and Montenegro CPR. The Oligocene and Cretaceous carbonate leads/prospects are associated with thrust fault related structures that are currently poorly defined on the currently available seismic. A new 3D seismic survey planned to be acquired in 2018 will improve the seismic imaging and help de-risk the trap definition.

Exploration work programme plan and outlook

Total investment over an exploration period of seven years from 2017 is estimated to be US$19 million, including the funding of a new 3D seismic survey (to cover an area not less than 338km^2), geophysical and geological studies, and the drilling of one well. The seismic survey and initial geophysical and geological surveys are to be completed within three years of the date of the concession agreement (the first exploration phase). Costs during this first exploration phase are estimated at US$5 million. The second, optional, four year exploration phase requires the drilling of one mandatory well to a depth not less than 2,800m (and the geophysical and geological studies necessary to complete such drilling).

Energean plans to begin the 3D seismic acquisition during the fourth quarter of 2018. Prior to conducting the 3D seismic acquisition the Group will complete various environmental surveys which will describe the mitigation measures to be applied prior to, during and after the 3D acquisition program. The Group plans to complete its 3D seismic survey in the first half of 2019.

The Directors believe that Montenegro has significant exploration potential for future oil and gas discoveries. The entry of ENI into four neighbouring blocks to those held by Energean, with significant exploration commitments, demonstrates the potential of the area. The Directors believe the ENI commitments comprise full 3D coverage and the drilling of two exploration wells (one of these will test the Cretaceous platform carbonates). The Directors believe that the presence of Energean, ENI and Novatek in Montenegro will precipitate significant investment in the Montenegrin oil and gas industry going forward.

6.4 Egypt

West Kom Ombo

Overview

West Kom Ombo is an exploration block in Upper Egypt, the licence for which expired in October 2017. The licence covered an area of 20,948km^2 after the first period relinquishment. Energean drilled the Apis-1 well which was plugged and abandoned on 9 September 2017 at a depth of 3,408 feet. Energean is currently assessing the amounts of recoverable costs spent during the latest drilling operations so as to apply for the release of the bank guarantee in respect of West Kom Ombo which is due to expire on 2 April 2018.

7. Field development for the Prinos basin

The Group is targeting the conversion of 2C resources to 2P reserves through the further development of the Prinos basin. The Prinos area development plan is currently being implemented and all main contracts have been tendered and awarded. With infrastructure already in place, and the Group having significant experience operating in this area, the Directors believe that the conversion of 2C to 2P is achievable at a comparatively low cost and risk.

The Group targets raising the recovery factor for the Prinos field to approximately 42% as per the NSAI Prinos CPR. The Group is also currently working to upgrade the static and dynamic models to reflect the new well data and to capture the dynamics that have left large sections of the reservoir pay unswept. The Directors believe that this updated understanding will be invaluable in determining and then targeting areas of remaining oil.

Various enhanced oil recovery techniques are under consideration for the Prinos oil field. These would target the remaining STOIIP and may include; miscible flood (CO_2 or H_2S) from produced gas; low saline water flood; and surfactants. The Group has completed a CO_2 flood study and intends to undertake a sampling and analysis programme in parallel with infill drilling. The Directors believe that the estimated expenditure and drilling and completion set out below are an accurate representation of the anticipated capital expenditure in the Prinos basin from 2017 to 2021.

	Drilling and completion ($ million)					Capex[1] ($ million)					
Year	Prinos A	Prinos B	Epsilon & WI	Charlie	Rig	Prinos & Prinos N	Epsilon	Charlie	WO	Other	Total Capex ($million)
2017	5.0				5.0	0.3			2.0		12.2
2018	17.6	15.3	28.2		20.2	2.0	43.6		3.1	3.1	133.1
2019		10.4	31.8		20.6	3.1	19.6	10.4	3.1		99.0
2020			12.7	21.2	21.0	3.7		10.6	2.1		71.4
2021				21.6	21.4	3.7			2.2		49.0
Total	**22.6**	**25.7**	**72.7**	**42.9**	**88.2**	**12.9**	**63.2**	**21.0**	**12.5**	**3.1**	**364.7**

Notes:
(1) Capex has been adjusted to reflect assumed inflation of 2.0% per annum from 2018 onwards.

Energean conducted a 340km^2 broadband 3D seismic survey over the Prinos Oil Field and its surrounding exploration area in the Gulf of Kavala during the summer of 2015. The survey also included a complex undershooting operation in the vicinity of the Prinos offshore platform. The final processed 3D cube was completed during the summer 2016 and the seismic interpretation including Quantitative Interpretation and pre-stack depth migration imaging is currently ongoing.

This new, high resolution 3D seismic data will enable Energean to optimise the location of future development wells within the main Prinos Field and the nearby Epsilon and Prinos North satellite oil fields. While there are currently no firm plans to drill new exploration wells, the 3D seismic data is being used to further evaluate existing prospects and leads and to identify new exploration opportunities, with the objective of increasing the contingent and prospective hydrocarbon resources within the Prinos basin The Group anticipates that in the region of 25 wells are likely to be drilled in the Prinos basin from the second half of 2017 to late 2021. The exact final number will depend on the results of the early Prinos infill wells and the unswept sections encountered, the SE Prinos step out well, the Epsilon ERD well and the appraisal of the various Prinos leads and prospects.

Energean's geological and geophysical team has already identified the following three appraisal opportunities within the Prinos basin, named Kazaviti, Athos and Delta:

- Kazaviti was originally discovered in 1976 and an additional discovery (Zeta) was made in 2016 during the deepening of a Prinos development well, PA-36. The Zeta discovery encountered sweet oil within an 8m sandstone layer (5m net pay) with no indication of a contact. The sands are thought to be stratigraphically trapped and the area is currently being further evaluated. According to the NSAI CPR, Kazaviti contains 0.9 MMbbls of 2C resources. Additional technical studies are currently ongoing to further assess the upside potential by identifying additional prospects and leads in the vicinity of PA-36.
- Athos is a sweet oil discovery made in 1982 which is poorly imaged on the historical seismic data. The prospect is being re-evaluated using the new 3D seismic data. According to the NSAI CPR, Athos contains 2.4 MMbbls of 2C resources.
- Delta was discovered in and tested sour oil from a stratigraphic deeper level than the Prinos North field. It was poorly imaged on the old seismic data, thus the prospect is currently under evaluation, using the new 3D seismic data. According to the NSAI CPR, Delta contains 1.6 MMbbls of 2C resources.

New exploration prospects have also been identified and booked as leads or prospects; these include Alpha, SE Prinos (B&C) and Epsilon Deep:

- Alpha lead is a fault bounded three-way dip closure located adjacent to the Prinos North field. The main reservoir unit comprise sandstones of the Prinos group and its proximity to the reservoir at Prinos North suggests similar rock characteristics, and the same oil water contact level and drive. According to the NSAI Prinos CPR the Alpha lead holds 6.3 MMbbls best estimate unrisked prospective resources.
- SE Prinos comprises a stacked 4 way dip closure structure on the equivalent B and C reservoir units which are producing at the Prinos oil field. The prospect can be drilled from the existing platform facilities and given discovery developed as a tie back to the existing production facilities. According to the NSAI Prinos CPR the SE Prinos prospect holds 2.6 MMbbls of best estimate unrisked prospective resources.
- Prospective resources have been identified within the Epsilon structure beneath the total depth of the Epsilon wells, at the deeper A2, B and C reservoir intervals, should the stratigraphy prove to be the same as that of the Prinos field.

The Group's production for the year ended 31 December 2017 averaged 2,803 bopd (2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down), with exit production at 31 December 2017 of 4,086 bopd. Actual production for the period 1 July to 31 December 2017 exceeded P50 and P90 estimates from 30 June 2017 by 14% and 39% respectively. In December 2017, the PA-37 production well was completed. The Group aims to achieve exit rate production of approximately 6,000 bopd by the end of 2018 and 11,000 bopd by the end of 2019. The Group aims to increase production to 12,899 bopd. Through the ongoing development of the Prinos basin, and the newly acquired 3D data, the Group is attempting to lower the cost of drilling development wells, while at the same time increase the amount of oil that can be produced. With respect to the Epsilon development plan, the Directors intend using horizontal well and multi-lateral technologies which, once demonstrated, could be replicated for other satellite discoveries.

Capital expenditure on the Prinos basin was US$49.5 million for the ten months ended 31 October 2017. The NSAI Prinos CPR estimates capital expenditure for Prinos development of US$133.1 million in 2018, US$99.0 million in 2019, US$71.4 million in 2020 and US$49.0 million in 2021 (figures reflect assumed inflation of 2.0% per annum from 2018 onwards). While the Group intends to invest these amounts in the Prinos development plan, there are no work commitments mandated under the Prinos basin licence, allowing the Group an element of flexibility as to when and how these amounts are spent.

8. Growth opportunities

The Group has identified several growth opportunities, both within its existing asset base and beyond. The Karish, Tanin, Prinos and Epsilon fields all contain potential further exploration prospects which would allow the Group to extend its resources in those areas. Additionally, the application of enhanced oil recovery techniques in the Prinos and Epsilon fields could also enable increased production from those fields.

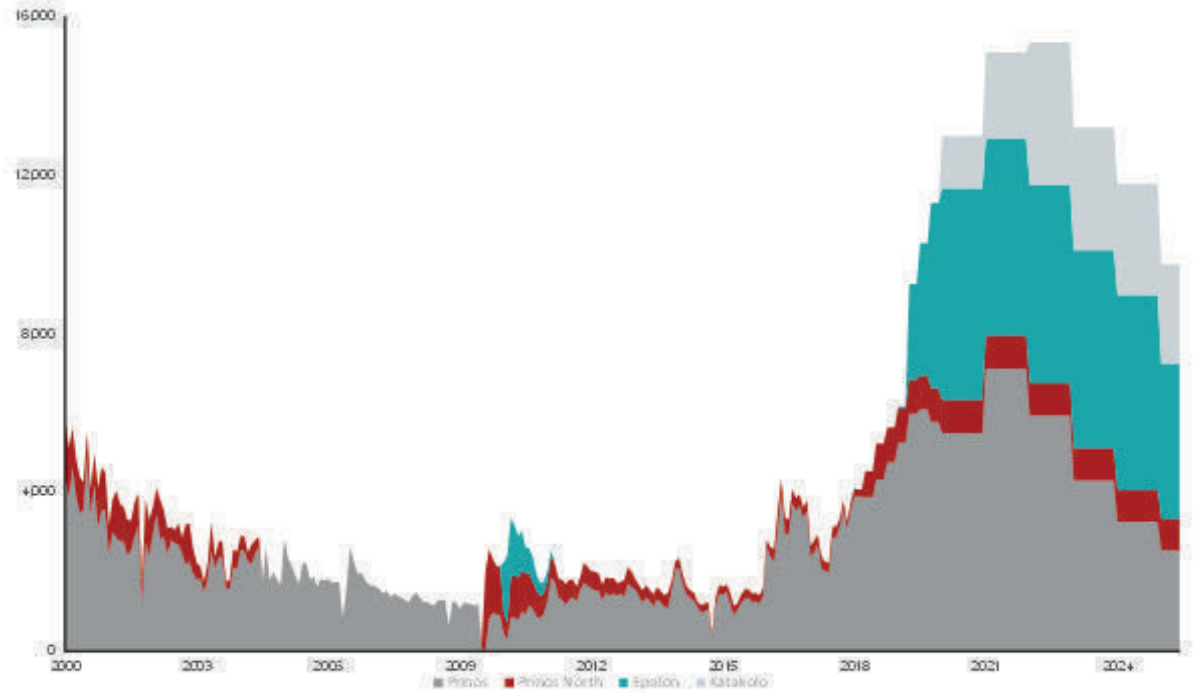
In terms of new prospects, the Group is considering pursuing assets in the regions where its operations are currently focused (including prospects in Italy, Albania, Cyprus, Tunisia and Croatia) and opportunities in emerging basins (including in the Eastern Mediterranean and in the Adriatic and Ionian basins).

In the Aegean Sea the Group is targeting prospects and leads within the Prinos basin as well as in the Orphanos and Thermaikos basins. The Eastern Mediterranean also has prospects within and beyond the Karish and Tanin fields, including the Karish North and East regions and Jurassic and lower Cretaceous prospects. In the Ionian Sea there are a number of prospects which the Group has identified. The blocks which the Group currently holds in the region (Blocks 30 and 26) have Cretaceous prospects that extend into currently unlicensed open acreage. There are also exploration prospects and leads in the Ioannina and Aitoloakarnania licence areas, and the Group has submitted an expression of interest in respect of an additional offshore area in the Ionian sea. The Group's exploration strategy in Egypt is to focus on proven petroleum systems, for example in the Nile Delta, the Gulf of Suez and the Western Egyptian Desert.

9. Production and drilling

9.1 Production Summary

The graph below sets out the Group's average daily production (in bopd) from the Prinos basin and Katakolo fields from 2000 to 2017, with projected production to 2024 based on data from the NSAI CPRs.



9.2 Drilling

Energean has accumulated extensive drilling experience across a number of its assets. More than 60 wells have been drilled offshore in the Prinos basin where Energean has been operating since 2007. Additionally, Energean drilled four wells onshore in Egypt under its previous licence. The extended reach drilling of a well during the Epsilon Field development set a record in the Mediterranean with a length of 5,297m in 2010. In 2014, Energean purchased its own drilling rig, Energean Force, which has been operating in the Gulf of Kavala since May 2015.

Energean has gas extraction and production experience garnered from its operation of the South Kavala gas field. Energean is currently extracting at the South Kavala field at a rate of 17,000 Nm3/day and 50-60 bbls of condensate oil for approximately three to five days a month.

Energean has carried out offshore geophysical, geotechnical and environmental base line surveys and a full petrophysical interpretation of wells in respect of the Karish and Tanin gas fields,

Additionally, in-field geotechnical investigations commenced in February 2018 and data will be fed into mooring analysis in order to develop the anchoring details for the FPSO to be deployed at Karish and Tanin.

Energean has extensive experience of safely and efficiently drilling and extracting oil and gas in challenging production conditions including high temperatures, sour gas, scale and complex crudes (asphaltene and inorganics).

Energean's core well engineering team members and will project management service providers have comprehensive experience of drilling operations that includes deep water projects west of Shetland and in West Africa as well as the Eastern Mediterranean.

10. Infrastructure

The majority of the Group's existing infrastructure in Greece is owned by the Greek state and provided to the Group rent-free for the life of the Lease in the Prinos basin. The Group is responsible for the costs of maintaining the facilities, however most of the decommissioning liabilities are retained by the Greek state. As the assets will be handed back to the Greek state when the final licence held in the Prinos basin expires in 2034 (an expiration date of 2024 with two 5 year extensions), without an obligation to decommission the plant, Energean does not recognise these assets on its balance sheet.

10.1 Sigma processing plant

The onshore Sigma processing plant has a capacity of 27,500 bopd and is located 14km east of the city of Kavala and 18km north of the Prinos platform complex. Its position is strategically advantageous in the North Aegean as it is close to all major planned oil and gas pipelines, has access to the sea and is connected to the Greek national gas and electricity grid. The plant undertakes crude oil desalination and dehydration, low pressure separation, crude oil stabilisation and storage (in three floating roof tanks with a combined storage capacity of 500,000bbls). Additionally, the Sigma processing plant carries out the following gas treatments; dehydration, H_2S removal and natural gas liquid recovery. The plant also undertakes residue gas compression and recycling offshore for gas lifting.

The plant also comprises both a sulphur plant and storage facilities (with sales made to a neighbouring fertiliser plant) and a 17MW combined cycle power plant (with the ability to expand). Energean has no abandonment liability in respect of the Sigma processing plant.

10.2 Tender assisted drilling rig—Energean Force

In 2014, Energean purchased and refurbished its own self-erecting drilling tender rig, "Energean Force", which has been operating in the Gulf of Kavala since May 2015. Energean Force has hull dimensions of 97.8m by 21.3m by 10.5m and has two cranes of 42m and 41m, respectively.

Energean Force has an operating water depth of 12m to 200m with a maximum drilling well depth of approximately 6km. It is a 2,000HP drilling rig with a capacity of 1,000kips, five engines (diesel) of 1,225KW and accommodation for 120 people. The rig has drilled six wells in Prinos and has executed multiple interventions and workovers. The wells were safely and efficiently drilled during extremely challenging market conditions for the industry. There are five days currently included in the budget to allow for maintenance for Energean Force between each well drilled.

The advantage to Energean of owning and operating its own drilling rig are:

- Cost control: direct rig costs are reduced;
- Operating efficiency: the rig's operating efficiency and availability is >97%;
- Operational focus: personnel and equipment have been specifically selected to deliver Energean's multi-well drilling and workover project; and
- Operating in remote areas: Energean is no longer reliant on an external rig contractor to ensure operations are properly supported to deliver wells on time.

10.3 Supply vessels

Valiant Energy

Offshore supply ship "Valiant Energy" supports Energean's ongoing investment programme in the Gulf of Kavala. Valiant Energy, which was constructed in Norway according to DN VGL's standards and has participated in oil and gas activities in the North Sea, is the first supply ship of this size and standard ever to arrive in Greece. It is 62.5m long and carries modern fire-fighting systems (FF3 water, FF2 foam) and can pump 7,500m³ of water per hour.

Valiant Energy is able to support any drilling program (for example, supply and carry platforms, equipment and material transportation to platforms and to jack-ups) and participate in anti-pollution and rescue operations, additionally it can collect and treat 155 people on board. Its overall length is 65.2m with a draft of 7.21m and a deadweight tonnage of 1,800 tonnes.

In May 2016, the Group sold the Valiant Energy to Seven Marine in a sale and leaseback arrangement.

Energean Wave

The supply vessel Energean Wave has an overall length of 47.2m with a draft of 3.8m. It can transport up to 60 people and has a maximum speed of 21 knots.

Since November 2016, both the Valiant Energy and the Energean Wave are leased under a two-year fixed term time charter with Seven Marine at an annual cost of US$4 million and US$2.4 million respectively. Under the time-charter arrangements, Seven Marine incur all costs relating to wages, fuel, crew and insurance related to the vessels.

10.4 Offshore Infrastructure

Energean's main facilities consist of:

- the Prinos Platform Complex (two production platforms "**Alpha**" and "**Beta**", one processing platform "**Delta**", one flare structure and inter-connecting bridges);
- the South Kavala gas production platform "**Kappa**";
- the oil and gas transport pipelines;
- the onshore processing and storage facilities in Nea Karvali, the "**Sigma Plant**"; and
- the offshore crude oil loading terminal and mooring facilities.

Prinos Platform Complex

The Prinos platform complex is located at the centre of the Prinos field. The offshore installation consists of two four-leg production platforms, Alpha and Beta. Each platform can accommodate 12 wells and is compatible with a jack-up rig, work-over rig and service rig. As of 9 February 2018, there were 12 active production wells, four water injection wells for reservoir pressure support and two inactive wells. At all times there is a work-over rig on one of the platforms and a service rig on the other platform.

As well as the four leg production platforms the Prinos platform complex also contains an 8-leg processing platform "**Delta**", with the necessary equipment for the following functions:

- three phase (oil, gas and water) production separation;
- test separator, for measuring the production performance of each well;
- crude dehydration;
- crude oil transfer to shore, with high pressure pump via an 8" submarine pipeline;
- sour gas dehydration with tri ethylene glycol ("**TEG**"), for the protection of the 12" submarine pipeline from corrosion;
- treatment of waste water for disposal (de-oiling and stripping);
- sea water injection in to the reservoir, for Prinos reservoir pressure support; and
- compression of sweet natural gas into the producing wells for gas lifting (enhanced oil recovery).

South Kavala Gas Facilities

Kappa Platform

The four leg platform, "**Kappa**", is 12km southwest of the Prinos platforms, and is the same design as the Alpha and Beta platforms of the Prinos Platform Complex. It accommodates two wells and is compatible with drilling, workover and service rigs. It is equipped with three-phase separation facilities, a gas booster compressor unit and a TEG gas dehydration unit. The platform has two deck levels; the lower deck contains a topsides completion system, a dehydration unit and the wellheads. The upper drilling deck has cabin style quarters and diesel power generation facilities.

The gas is dehydrated and then exported to the offshore oil production platform at Prinos, where it is used for fuel and gas lift. Total annual gas production at South Kavala was 687,333 Nm^3 in 2017.

10.5 Pipelines

Seven pipelines are used for the transport of hydrocarbons in the Prinos basin as follows:

- 6" submarine pipeline of 12km length for the transfer of dehydrated sweet natural gas from Kappa to Delta platform;
- 12" submarine pipeline of 18km length for the transfer of dehydrated sour natural gas from Delta platform to the onshore facilities;
- 8" submarine pipeline of 18km length for the transfer of dehydrated sour crude oil from Delta platform to the onshore facilities;
- 5.3" submarine pipeline of 18km length for the transfer of dehydrated sweet natural gas from the onshore facilities to Delta platform for gas lifting the production wells;
- 6" underground pipeline of 7km length for the transfer of dehydrated natural gas from the network of Public Gas Corporation, at PFI facilities, to the onshore facilities;
- 24" submarine pipeline of 3km length for the transfer of stabilised crude oil from the storage tanks to the tanker compartments; and
- 16" submarine pipeline of 3km length for the transfer of ballast from the tanker compartments to the onshore ballast storage tank.

10.6 Auxiliary Systems

The following auxiliary process systems support the operations at Prinos:

- flare system (hydrocarbon and acid gas flare collection headers and blow-down drums);
- process liquid drainage system and network;
- nitrogen and purge gas supply and distribution system;
- sulphuric acid and caustic soda storage and supply system;
- steam generation and distribution system and condensate recovery;
- water demineralisation unit for BFW;
- sour water treating; and
- ballast and oily water storage and treating facilities.

The plant operation and maintenance is also supported by the mooring facilities (3km from Sigma shore), the supply boat Epsilon, two crew boats (Akra Prinos and Skala Prinos) and a barge (Limin Prinos).

10.7 New Platforms

A new fixed platform ("**Lamda**"), designed to be a minimum facility normally unmanned, is planned to be installed in the first half of 2019 in the Epsilon oil field. The platform incorporates the requirement to support the Energean Force tender assist rig drilling program. A FEED study and near finalised detailed design has been performed by Offshore Design Engineering Limited (ODE UK).

Lamda is a four leg fixed platform normally unmanned, designed for water depths of 40m, with a driven piled foundation design. The platform is transported to the field on a flat top cargo barge and installed according to common industry practice with a floating crane.

The installation of Lamda is a part of Energean's investment programme for the Prinos basin and will contain slots to allow up to 15 wells to be drilled. Energean has also developed a full field plan to connect the greenfield facilities by rigid pipeline to the existing offshore processing facility (Prinos Delta).

The construction and fabrication contract award for the new facilities occurred in December 2017 with installation planned for the second quarter of 2019.

The Group is also considering the development of an additional platform ("**Charlie**"). The design of the Charlie platform is still at an early stage but it is expected to be a bridge linked platform installed adjacent to the Prinos Beta platform and will be used for the drilling of additional infill wells in the Prinos basin. The platform will be similar in style to the Lamda platform and will have the capacity for up to 15 well slot. The existing Lamda design and configuration will be used as the starting point and modifications made to suit the specific requirements of the Charlie facilities. The main difference between Charlie and Lamda is expected to be that the Charlie platform would not be a stand-alone facility and the platform systems would be fully integrated with those on the Prinos platform thus keeping the Charlie facilities to a minimum.

10.8 2017 Facilities Turnaround

Energean carried out successfully a two-week turnaround of the Group's onshore and offshore facilities in Nea Karvali, Kavala, for the inspection and maintenance of the offshore and onshore facilities. Such turnarounds are routine and conducted, on average, every three years. The turnaround is necessary to carry out a variety of works including cleaning, inspection and maintenance jobs and to ensure the continuous safe operation of the offshore and onshore process facilities and to achieve the required certification by DNV-GL.

The overall cost associated with the turnaround was approximately €1.2 million, below the budgeted amount of approximately €1.4 million. The turnaround activities were carried out smoothly and effectively by implementing the established operations, maintenance and safety procedures, with no serious incidents. The production wells were shut in for a period of 18 days in September and October 2017.

A large number of contractor personnel was used to execute the scheduled jobs. On average, 35 and 61 contractor personnel (qualified, experienced and well trained technicians and labourers) worked daily offshore and onshore, respectively, for the duration of the shut-down. An additional 23 contractors performed tasks both onshore and offshore for the duration of the turnaround. Inspections were witnessed by a DNV-GL inspector (independent certifying authority) who acknowledged the good condition of the facilities and certified their continued safe operation. The Group managed production at an average rate of over 3,700 bopd in October 2017 to confirm individual well performance after the scheduled turnaround.

11. Environmental, health and safety, and corporate social responsibility

Like other participants in the oil and gas exploration and production industry, Energean is subject to various HSE laws and regulations administered by local, national and other government entities, and similar agencies in the countries and regions in which Energean operates. The Directors believe that Energean is currently in compliance with all material governmental laws and regulations affecting its business and maintains all material permits and licences relating to its operations.

A strong HSE performance is a key aspect of the Group's overall business success. In 2014 and 2015 the Group had a lost time incidents frequency rate ("**LTIFR**"), excluding contractors, of nil, with an LTIFR of 3.5 in 2016 and 3.9 in 2017. LTIFR is calculated on the basis of all recordable lost time incidents multiplied by 1,000,000 and divided by the total man-hours.

Energean's HSE policies incorporate guidance from the International Marine Contractors Association, the International Association of Oil and Gas Producers and the International Association of Drilling Contractors. Those policies are supplemented by applicable codes and standards recommended by industry classification societies, client safety policies, and sovereign laws. Generally, the Group seeks to apply the most stringent applicable standards.

The HSE framework employed by Energean includes:

- an HSE and social responsibility policy;
- an HSE plan;
- drilling rigs worldwide HSE standards; and
- a stop work policy.

11.1 Environmental

Energean applies the precautionary principle, supporting international initiatives, in order to minimise its environmental impact. In this respect, all employees are encouraged to act in an environmentally responsible manner, and the Group offers training for raising awareness on current and new environmental issues. Energean recognises the importance of understanding the impact of its activities on the environment and is therefore developing environmental programs for the continuous improvement of its environmental management system.

Energean's environmental strategy is built around the following ideas:

- full compliance with environmental laws and regulations;
- continuous development of Energean's environmental management system;
- development of initiatives that preserve natural resources and quality of life in the areas where Energean operates;
- reduction of Energean's environmental footprint;
- promotion of the involvement of associates and employee representatives in the process of safeguarding the environment; and
- support of environmental projects that promote sustainable development.

Energean's environmental concern is addressed throughout its value chain and it makes investments to reduce its carbon footprint and waste and to promote energy and water efficiency. Energean's workforce has demonstrated that heavy industrial activity can be compatible with everyday social activity.

A specific example of Energean's ongoing work to ensure adherence to its environmental objectives is its continuous monitoring of air quality. In the wider area of Thasos and Kavala, 12 monitoring stations censor the total sulfation of the atmosphere on a monthly basis and a central environmental station analyses H_2S, SO_2 and HC levels and measures meteorological data (wind speed and direction, rainfall height, ambient temperature).

Energean has additionally formed specific emergency response procedures, such as for handling oil spills. Energean has trained staff and what it considers sufficient equipment (comprising boats, booms, oil spill collectors, chemical solvent, modern absorbent materials) for combating oil contamination of the sea.

Energean's ability to operate in environmentally sensitive regions is reflected by the award of over 10 blue flags by the Hellenic Society for the Protection of Nature (representing Greece in the international Foundation for Environmental Education) every year since 2008 to beaches and marinas in the areas surrounding the Prinos basin. In order to qualify for a blue flag, a beach must satisfy several criteria including in relation to water quality and the monitoring of marine and freshwater sensitive habitats.

11.2 Health and safety

Energean is committed to protecting the health and safety of all individuals potentially affected by its corporate activities, including its employees, contractors and the public. The Group strives to provide a safe and healthy working environment and not to compromise the health and safety of any individual.

Energean's HSE process is based on established practices in managing HSE risks in the oil and gas industry. The HSE management system which Energean has implemented seeks to ensure that Energean:

- Understands all hazards associated with their operations;
- Undertakes activities to manage those hazards and minimise the risk level;
- Measures the effectiveness of its HSE performance; and
- Adjusts its plans and procedures in response to those assessments.

Energean implements emergency plans, provides training to its employees and promotes a positive health and safety culture. All employees are responsible and accountable for contributing to a safe working environment and for fostering safe working attitudes.

Formal training on health and safety is provided to all relevant employees either annually or once every two to three years depending on the category of training to be provided. Energean operates a "permit to work" system which aims to ensure the safety of any employee or contractor working for Energean by ensuring that all necessary safety systems are in place, before, during and after a job is completed.

Energean also carries out weekly rig and accommodations safety inspections and requires all accidents, or near misses, to be reported to the appropriate manager and to the HSE manager. Additionally, any person employed and/or contracted by Energean may exercise a "stop work" policy if they feel that any employee, a company's assets or the local environment is at risk. There shall be no fault put on any employee calling for a stop work order in good faith even if, upon investigation, the stop order proves to be unnecessary.

Health and safety incidents

Year	Average Employment	Man-hours	Total Number of Lost Time Incidents (LTI)	LTI Frequency Rate[1] (LTIFR)
2017	386	778,008	3	3.9
2016	363	570,410	2	3.5
2015	332	592,708	0	0
2014	256	403,200	0	0

Notes:

(1) Frequency rate is for Group employees (excluding contractors), calculated on the basis of all recordable LTI multiplied by 1mln and divided by the total man-hours.

11.3 Corporate social responsibility

Operating in a responsible and sustainable manner is essential to Energean. Energean runs its business in line with the expectations of its stakeholders, and sees Corporate Social Responsibility ("**CSR**") as a discipline that helps it to manage risks and maximise on the opportunities presented to it in a changing world.

Energean's objective is to generate sustainable prosperity through its business operations. Therefore Energean is committed to conducting its business responsibly, which means safeguarding the health and safety of its employees, caring for the environment, supporting the local communities in which Energean operates, meeting their expectations and needs and contributing to the sustainable development of those communities.

The Chief Executive assumes ultimate accountability for CSR supported by the CSR Team. The Board has ultimate responsibility for reviewing and approving the CSR strategy and monitoring the achievement of sustainability objectives through reviewing regular performance reporting. All business units are accountable for developing and driving implementation of the Group's CSR strategy and targets structured under this policy. Progress against the Group's CSR strategy is independently assured where appropriate.

Energean also has strong relationships with local communities in Greece and its recent corporate social responsibility initiatives include the following:

Ongoing	Close collaboration with the Eastern Macedonia and Thrace Institute of Technology including providing training, lectures, scholarships and internships for the MSc in Oil and Gas Technology and the MSc in Petroleum Engineering Technology
2017	Donation for the purchase of bulletproof vests for the Police Department of Kavala
2016	Donation to Kavala fire station for the repair of the only crane vehicle in the region
	Donation of three automated external defibrillators (AED) placed at remote areas of the Ioannina Prefecture
	Donation for medical supplies to refugees and to provide basic supplies for child refugees stranded in Kavala
2015	Donation of personal protection equipment to Kavala volunteer firemen
	Donation to Kavala special education elementary school
2014	Repair of Kavala ambulance vehicles

11.4 Anti-corruption policies

Energean adopted revised corporate governance policies on 2 March 2018, including an anti-corruption and bribery policy which sets out Energean's responsibilities, as well as the responsibilities of those working for them, in observing and upholding Energean's position on bribery. It also provides information and guidance to those working for Energean on how to recognise and deal with bribery and corruption issues.

The Group's Code of Conduct contains provisions relating to bribery and corruption which set out the Group's policy of conducting all its business in an honest and ethical manner and in compliance with all applicable anti-bribery laws, including but not limited to all applicable local laws where the Group operates and the Bribery Act 2010 (the "**Bribery Act**"), and to accurately reflect all transactions on the Group's books and records.

The Group takes a zero tolerance approach to bribery and corruption and is committed to acting professionally, fairly and with integrity in all its business dealings and relationships wherever it operates. The Group's Code of Conduct prohibits bribery and corruption in any form by employees, contract staff or industry partners working on its behalf.

12. Offtake and marketing

12.1 BP Offtake Agreement

The Group signed the BP Offtake Agreement with BP on 4 April 2013; this was subsequently amended in 2014, 2016 and February 2018, when it was extended to the later of 1 November 2025 or total delivery of 25 MMbbls of oil to BP. The BP Offtake Agreement includes the BP General Terms and Conditions for Sales and Purchases of Crude Oil, 2007 edition, and is governed by English Law.

Subject to the terms and conditions precedent of the agreement, the Group agrees to sell, and BP agrees to purchase, 100% of the Group's entitlement to the crude oil production lifted from the Prinos, Prinos North and Epsilon fields, i.e. 100% of the lifted production. The agreement thus secures sales of crude oil produced and limits the Group's exposure to offtake risk.

The original agreement was signed on 4 April 2013, and subsequently amended on 14 February 2014 (with effective date of 13 January 2014), 19 January 2016, 18 May 2016 and 2 February 2018, and remains in full force and effect until the later of 1 November 2025 or delivery of 25 MMbbls of oil to BP. The Group and BP may further agree to extend duration of the agreement for additional 12 months periods. The Group has also undertaken to provide BP with a right of first refusal for BP in respect of all crude oil entitlements from any other field acquired by the Group throughout this duration.

The crude oil sold and purchased under the agreement shall be given and taken FOB at the delivery point, which is currently located outside the Prinos onshore installations at the loading flange of the Prinos conventional buoy mooring delivery hose which connects to the permanent intake flange of BP's vessel receiving oil. The cargo sizes are scheduled for the first 12 months at 200,000 bbls and afterwards in amounts not to exceed 350,000 bbls. Subject to the maximum cargo sizes, BP will schedule and nominate each cargo so that not more than 20,000 bbls will remain in the crude oil storage tanks after loading of the nominated quantity. As of 31 December 2017, approximately 4.0 MMbbls had been delivered under the BP Offtake Agreement since June 2013.

The US$ FOB price per bbl is determined in accordance with an "A+B—C+D" formula where:

- "A" means the average dated Brent price published in the Platts Crude Oil Marketwire for dated Brent during month M or M-1 at buyer's option (the "**Pricing Period**");
- "B" means the Platts Urals RMCB which is the Platts Urals RCMB differential to dated Brent for Pricing Period;
- "C" means US$6.40 unless a price revision trigger event occurs and is continuing in months M—2 and M—1, in which case means US$7.00/bbl for the relevant cargo; and
- "D" means the API escalator of Average dated Brent for month M/150*(API-29.5) where API is up to a maximum of 33.

BP may upon specified price revision trigger events request a re-evaluation of the price formula. According to the agreement, a price revision trigger event occurs if the Kirkuk European Official Selling Price is US$3.00/bbl less than the Platts Urals RCMB differential to dated Brent or if the Basrah European Official Selling Price is US$5.50/bbl less than the Platts Urals RCMB differential to dated Brent. If, during the period from and including the fourth year of the agreement, a price revision trigger event is continuing for a period of three consecutive months, BP may request a re-evaluation of the price formula. In the event the parties fail to agree upon a revision of the formula within 30 days from the request, either party may terminate the agreement by giving six months written notice.

The agreement contains provisions on early termination and suspension rights for BP if any of the following events occur:

(a) the Group produces on average less than 30,000 bbls per month for three consecutive calendar months for other reasons than mechanical failure, maintenance or force majeure;

(b) change of control of the Group where the new controlling entity does not meet a number of qualitative requirements, specified in the agreement;

(c) breach by the Group of specified representations and warranties pertaining e.g. to legal title to the crude oil and required consents and authorisations;

(d) oil fails to meet agreed specifications; and

(e) Group's breach of provisions relating to health, safety, security and the environment.

Further, both parties are entitled to early termination after 2 years of the BP Offtake Agreement by giving 3 months prior notice to the other party if the average rate of total oil production does not exceed 2,500 bopd on average over the immediately preceding 90 consecutive days.

According to the agreement, the Group may not enter into a farm in/farm out or any other transaction with a third party which may potentially reduce its entitlement to the oil below 100% without the prior written consent of BP.

Neither of the parties may assign the agreement or any rights and obligations thereunder without the previous written consent of the other party. Such consent shall not be unreasonably withheld or delayed.

12.2 Gas Supply Agreements

Energean Israel has entered into a number of Gas Supply Agreements with certain buyers in Israel for the provision of natural gas from the production of first gas at Karish. The total volume of gas contracted to be provided is approximately 61 BCM (excluding the Or Gas Supply Agreement, 74 BCM including Or) in aggregate if all relevant conditions are satisfied, with an annual gas supply following commissioning and transition periods of between approximately 4.2 BCM per annum on an ACQ basis (or 3.1 BCM per annum on a take or pay basis), excluding the Or Gas Supply Agreement (up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis or approximately 3.3 to 3.8 BCM per annum on a take or pay basis including the Or Gas Supply Agreement), assuming, inter alia, 95% uptime and reasonable maintenance. The weighted average tenor of the Gas Supply Agreements signed to date is 16.1 years.

For a discussion of certain key risks relating to the Gas Supply Agreements, see *"Risk Factors— Risks relating to the Group's business and industry—1.3. The Group will be dependent on the purchasers under its Gas Supply Agreements*".

Terms Common to All Gas Supply Agreements

The Gas Supply Agreements are governed by Israeli Law.

The gas price mechanism is denominated in US dollars and is predominantly based on a linkage to the Israeli electricity production component index as published by the Israeli Electricity Authority and, in some cases, to the exchange rate between the US dollar and the New Israeli Shekel, and with a small percentage (less than 5%) of the contracted quantity of gas indexed to oil. The weighted average contract price was US$4.11/mmbtu as of 27 February 2018 based on the then-current Israeli electricity production component index, Brent oil price and exchange rates. The gas price in each Gas Supply Agreement is underpinned by a specified price floor denominated in US dollars. The weighted average floor price was US$4.06/mmbtu as of 27 February 2018 (adjusted for inflation to make comparable to current prices). The price floor is fixed, except in respect of certain buyers, representing approximately 14% of aggregate ACQ, whose floor price may reduce by approximately 5% only in the event the Israeli electricity production component index falls below a specified threshold. In addition, certain buyers affiliated with each other and representing up to approximately 62% of aggregate ACQ, are entitled to receive credits from Energean Israel, notwithstanding the floor price, equal to the difference between (i) such buyers' contract price and the weighted average contract price of sales to others not affiliated with such buyers (where the latter is lower) and (ii) the difference between such buyers' contractual floor price and the revenue per unit of sales to others not affiliated with such buyers (where the latter is lower). This price adjustment clause is subject to compliance with Israeli law. Under the Gas Supply Agreements, the floor price in respect of certain other entities is due to increase after a specified number of years unless affiliates of such entities enter Gas Supply Agreements for further supply volumes.

The Gas Supply Agreements are linked to existing supply contracts with Tamar and Leviathan and, as regards the majority of the Gas Supply Agreements, in accordance with relevant antitrust exemptions or the NGF, as applicable, during a three-year, predetermined window, the majority of the buyers are entitled to notify Tamar or Leviathan, as applicable, of its decision to reduce the quantities of gas it purchases, to a quantity equal to 50% of the average annual contract quantity consumed in the three years prior to the date of the buyer's notification, or with respect to the Gas Supply Agreements of Alon Tavor, Ramat Gavriel, and OPC Hadera (with respect to OPC Hadera, regarding certain quantities), of its decision to terminate its Gas Supply Agreement with Tamar in its entirety. For further information on the NGF and antitrust exemptions, see *"Regulatory Overview— Regulatory and legislative framework in Israel—Government Regulations"*.

The Gas Supply Agreements provide for a daily contract quantity of zero during the commissioning period and certain Gas Supply Agreements provide for reduced DCQs during a twelve month transition period (the **"Transition Period**") following the provision of a reduction notice from the buyer to sellers under its existing Gas Supply Agreement requesting a reduction in supply quantities as set out above. Following the Transition Period, the DCQ is a quantity, as set out in each Gas Supply Agreement.

The buyer is entitled to reject off-specification gas. Prior to issuance of an off-specification notice, Energean Israel is liable for expenses and costs directly resulting from off-specification gas consumption, including in relation to damage caused to or cleaning of the buyer's facilities and transportation facilities.

The Gas Supply Agreements include a take or pay mechanism in accordance with which, the buyers undertake to take or pay for a minimum annual quantity of gas, as determined in the respective agreements as a percentage (about 75% by weighted average) of the average ACQ (which is equal to the DCQ multiplied by 365) less certain adjustments for buyer's or seller's force majeure and off-specification gas and other factors ("**Adjusted ACQ**").

In addition, the take or pay amount may be reduced in any given year by the total amount of gas in excess of the applicable take or pay amount which was delivered and paid for over a limited number of preceding years and carrying forward this quantity as a credit against the take or pay amount, up to a maximum reduction of around 30% on average of ACQ in any given year (thereby reducing the take or pay quantity in that year by a corresponding amount). Yet over the life of the Gas Supply Agreements, the buyers are in effect obliged to take, on average, the take or pay quantity applied to the aggregate of the Adjusted ACQs applying in each year.

When a buyer has taken a quantity above a threshold each year (the minimum take or pay threshold), make-up gas already paid for but not taken under the take or pay mechanism can be recovered free of further charge. Make-up aggregate (and carry-forward aggregate, as above) accrued by the end of each year can be used only during a limited period following its accrual. Failure of Energean Israel to deliver a buyer's properly nominated quantity entitles the buyer to liquidated damages, with certain exclusions, set as a percentage reduction of the contract price (known as shortfall).

Parties also have certain maintenance rights that may reduce the take or pay quantity by approximately 10 to 20 days per year times the DCQ on average over a four-year cycle. The maintenance nominations affect the DCQ on the day in question and thus, may affect the ACQ in the annual reconciliation.

In addition, the Gas Supply Agreements include provisions for the buyers to provide financial security (either a letter of credit or bank guarantee issued by a bank with a specified credit rating) in predetermined circumstances where the buyers do not meet certain creditworthiness thresholds.

If the availability date of gas for commissioning has not occurred by certain dates (differing for each contract), in the case of all but one Gas Supply Agreement, Energean Israel is liable for liquidated damages in the form of early shortfall. In the case of some buyers, this availability date must occur by the last date of a four-year window period following satisfaction of seller's conditions, to be nominated by Energean Israel. In the case of other buyers, the date of end of commissioning must occur by mid-2021. The Group estimates its potential exposure to such liquidated damages to be approximately US$50 million in total, although the Group also believes this risk will be covered by liquidated damages provisions in the Technip EPCIC Contract. Part of such damages is to be paid in cash, up to a cap, and part deferred to later gas deliveries under the contract at a discount in the same manner as normal shortfall.

The Gas Supply Agreements contain provisions on early termination rights for the buyers in certain circumstances, including if any of the following events occur, inter alia:

(a) failure of Energean Israel or the buyer to fulfil its conditions by set milestones including, in the case of certain buyers, in the event well completion is delayed beyond June 2020 (subject to specific extension for force majeure)

(b) delay in the end of commissioning of Energean Israel's facilities in respect of Karish and Tanin relating to the construction of the transportation system or set milestones, including:

- in respect of certain buyers, making gas available to start commissioning by the end of the applicable window for such buyer's notification of reduction to its existing seller;
- in the case of certain other buyers not subject to a reduction window, making available gas to start commissioning by fixed dates ranging from November 2021 to June 2024 (including a 60 day notice period and subject to specific extension for force majeure);

(c) extended force majeure (which includes events affecting the buyer's and the seller's respective facilities);

(d) an act of insolvency in respect of Energean Israel; and

(e) breach of Energean Israel's material obligations.

In the event of a dispute, the Gas Supply Agreements provide for referral to an expert or arbitration dispute resolution procedures in accordance with the International Chamber of Commerce Rules of Arbitration or under the London Court of International Arbitration, with seat in London (or Tel Aviv in the case of minor disputes below a defined de minimis threshold).

The parties grant indemnities to each other in respect of breach of their respective warranties.

Agreements with Dalia and Or Power

Energean Israel entered into two Gas Supply Agreements with Dalia and Or Power on 25 May 2017.

Subject to the terms and conditions precedent of each Gas Supply Agreement, Energean Israel agrees to sell, and the buyers agree to purchase, natural gas during the contract period of approximately 15 years for Dalia and 20 years for Or Power from the first commercial flow of gas. The main conditions precedent for the Gas Supply Agreements are: both parties obtaining antitrust consent; for Energean Israel, first drawdown under the Senior Credit Facility for development of the Group's facilities and, for the buyers, approval of the Dalia Gas Supply Agreement by Dalia's existing lenders and financial closing by Or Power as set out in its Gas Supply Agreement for the development of Or Power's facilities, respectively.

In addition, the agreement with Or Power is contingent on Or Power succeeding in its application to receive a new licence from the Electricity Authority to construct a new power generation plant in Israel and successfully completing this project. According to the Electricity Sector Law and its regulations, Or Power, like any other entrepreneur, is required to obtain a conditional production licence in order to be able to construct its proposed power generation plant, to be replaced by a permanent production licence following its commercial operation. Any applicant for a conditional licence must demonstrate certain conditions which were prescribed in the regulations, inter alia, the feasibility of the connection of its proposed power station to the electricity transmission network, that it has the required financial capacity (a minimum requirement of injection of 20% equity to the project) and to demonstrate its rights on the land where such power station is planned to be constructed. In addition, the Electricity Authority decides whether to grant conditional production licences based on the regulatory framework in place regarding each technology and the quotas determined therein. See also Part 7 *"Regulatory Overview—Regulatory and Legislative Framework in Israel—Government Regulations—Regulatory Framework for Conventional IPPs"*. While the Directors believe this will occur, and that the project will be completed by between 2023 and 2025, there can be no guarantee that Or Power will be successful in its licence application, that the project will be completed successfully or that Or Power will reach financial closing as set out in the Or Power Gas Supply Agreement.

The Dalia Gas Supply Agreement provides for a DCQ which equates to approximately 0.3 BCM per annum for the Transition Period. Subsequently, the DCQ will equate to approximately 0.5 BCM and 0.7 BCM per annum. The Or Power Gas Supply Agreement provides for a DCQ which equates to approximately 0.5 to 0.7 BCM per annum. Or Power may elect to increase or decrease its DCQ by the equivalent of approximately 0.1 BCM per annum within 30 days from satisfaction of its condition precedent and by the equivalent of approximately 0.03 BCM per annum within 30 days of the Start Date. Approximately five years from the first commercial flow of gas under a contract for the supply of an equivalent volume of gas from Leviathan, Or Power is required to exercise its reduction option under the Leviathan agreement and increase the DCQ of the Group's Gas Supply Agreement by an equivalent amount. The Group's estimate of this quantity is 50% of the assumed DCQ.

Under the Or Power Gas Supply Agreement, Energean Israel is liable to pay delay liquidated damages based on shortfall gas for delay in commissioning.

Energean expects the total contract quantity for both Gas Supply Agreements together to amount to approximately 22 BCM over the contract period if all conditions are satisfied.

Agreements with Ramat Negev and Ashdod Energy

Energean Israel entered into two Gas Supply Agreements with Ramat Negev and Ashdod Energy on 30 October 2017.

Subject to the terms and conditions precedent of each Gas Supply Agreement, Energean Israel agrees to sell, and the buyers agree to purchase, natural gas during the contract period of at least 14 years from the first commercial flow of gas. The main conditions precedent for the Gas Supply Agreements are, for Energean Israel, financial closing under the Senior Credit Facility and FID for development of the Group's facilities and, for the buyers, approval of the applicable Gas Supply Agreement by Ramat Negev's or Ashdod Energy's existing lenders, respectively.

The Ramat Negev Gas Supply Agreement provides for a DCQ which equates to approximately 0.1 to 0.14 BCM per annum for the first two years following the start date and a DCQ which equates to approximately 0.1 to 0.13 BCM per annum thereafter. The Ashdod Gas Supply Agreement provides for a DCQ which equates to approximately 0.05 to 0.07 BCM per annum for the first two years following the start date and a DCQ which equates to approximately 0.05 to 0.06 BCM per annum thereafter.

In the event that Ramat Negev's facilities or Ashdod's facilities no longer qualify as a production unit in cogeneration under the Cogeneration Regulation, Ramat Negev or Ashdod, as the case may be, may reduce its DCQ by up to 35% (with subsequent increase of the DCQ by the same quantities reduced after regaining the status of a production unit in cogeneration).

Under the Gas Supply Agreements with both Ramat Negev and Ashdod Energy, Energean Israel is liable to pay delay liquidated damages based on shortfall gas for delay to commissioning.

Energean expects the total contract quantity for both Gas Supply Agreements together to amount to up to approximately 2.4 BCM over the contract period if all conditions are satisfied.

If a Concluding Force Majeure Event occurs, as this term is defined under the regulations pursuant to the Electricity Sector Law, the buyer may be entitled to assign the agreement to the "System Manager", who may be entitled pursuant to such regulations to terminate the agreement upon the provision of 90 days' notice.

Agreement with Dorad

Energean Israel entered into a Gas Supply Agreement with Dorad on 30 October 2017.

Subject to the terms and conditions precedent of the Gas Supply Agreement, Energean Israel agrees to sell, and the buyer agrees to purchase, natural gas during the contract period of at least 14 years from the first commercial flow of gas. The main conditions precedent for the Gas Supply Agreements are, for Energean Israel, financial closing under the Senior Credit Facility and FID for development of the Group's facilities and, for the buyer, approval of the Gas Supply Agreement by Dorad's existing lenders.

The Dorad Gas Supply Agreement provides for a DCQ which equates to between approximately 0.35 to 0.54 BCM per annum.

Energean expects the total contract quantity of the Dorad Gas Supply Agreement to amount to up to approximately 6.9 BCM over the contract period if all conditions are satisfied.

Under the Dorad Gas Supply Agreement, Energean Israel is liable to pay delay liquidated damages based on shortfall gas for delay to commissioning.

If a Concluding Force Majeure Event occurs, as this term is defined under the regulations pursuant to the Electricity Sector Law, the buyer may be entitled to assign the agreement to the "System Manager", who may be entitled pursuant to such regulations to terminate the agreement upon the provision of 90 days' notice.

Agreements with Alon Tavor and Ramat Gavriel

Energean Israel entered into two Gas Supply Agreements with Alon Tavor and Ramat Gavriel on 7 December 2017.

Subject to the terms and conditions precedent of each Gas Supply Agreement, Energean Israel agrees to sell, and the buyers agree to purchase, natural gas during the contract period of at least 17 years from the first commercial flow of gas. The main conditions precedent for the Gas Supply Agreements are, for Energean Israel, financial closing under the Senior Credit Facility and FID for development of the Group's facilities and, for the buyer, approval of the applicable Gas Supply Agreement by Alon Tavor's or Ramat Gavriel's existing lenders, respectively.

The Alon Tavor Gas Supply Agreement provides for DCQ which equates to approximately 0.15 BCM per annum. The Ramat Gavriel Gas Supply Agreement provides for a DCQ which equates to approximately 0.15 BCM per annum.

In the event that Alon Tavor's facilities or Ramat Gavriel's facilities no longer qualify as a production unit in cogeneration under the Cogeneration Regulation, the affected party may reduce its DCQ by up to the equivalent of approximately 0.04 BCM per annum (with subsequent increase of the DCQ by the same quantities reduced after regaining the status of a production unit in cogeneration).

Energean expects the total contract quantity for both Gas Supply Agreements together to amount to up to approximately5 BCM over the contract period if all conditions are satisfied.

If a Concluding Force Majeure Event occurs, as this term is defined under the regulations pursuant to the Electricity Sector Law, the buyer may be entitled to assign the agreement to the "System Manager", who may be entitled pursuant to such regulations to terminate the agreement upon the provision of 90 days' notice.

*Agreements with related entities having the Israel Corporation as a common shareholder ("**IC Corporation**")*

Energean Israel entered into four Gas Supply Agreements with entities of the IC Corporation, as follows: ICL, ORL, OPC Hadera, and OPC Rotem on 6 December 2017.

Subject to the terms and conditions precedent of each Gas Supply Agreement, Energean Israel agrees to sell, and the buyers agree to purchase, natural gas during the contract period of at least 15 years from the first commercial flow of gas (except in the case of ICL, which has a right to terminate its Gas Supply Agreement before the end of its contract term upon expiry of the Dead Sea Works Concession, but no earlier than 31 March 2030 under certain conditions). The main conditions precedent for the Gas Supply Agreements are, for Energean Israel, financial closing under the Senior Credit Facility and, for all four IC Corporation buyers, shareholder consent. Such shareholder consent has already been obtained in respect of OPC Rotem, OPC Hadera and ORL. In the case of ORL, a shareholder derivative suit was filed by a shareholder of ORL against ORL's directors and others (not including the Company). The suit contested the shareholders' general meeting approval process regarding the Gas Supply Agreement signed by ORL and sought (i) the invalidation of the ORL shareholders' general meeting approval of the ORL Gas Supply Agreement (which was granted by a 99.95% majority of the disinterested shareholders of ORL approximately a week following filing of this suit) and (ii) a reallocation of the benefits between the IC Corporation-affiliated entities, in accordance with the bargaining power of each entity without an effect on the total gas terms on which the gas would be purchased from the Group. An additional condition precedent for the OPC Rotem and OPC Hadera Buyers is approval of the applicable Gas Supply Agreement by OPC Rotem and OPC Hadera's existing lenders, respectively). A joint condition precedent of Buyer and Seller is receipt of approval of the Gas Supply Agreements by the Israel Antitrust Authority.

For the OPC Hadera and OPC Rotem Gas Supply Agreements, during the Transition Period, each buyer shall use reasonable endeavours to take and the seller to supply the difference between the buyer's consumption needs and the buyer's take or pay commitment under its existing Gas Supply Agreement, plus any make-up aggregate quantities due to the buyer under its existing Gas Supply Agreement or such higher amount notified by buyer up to the DCQ. During this period, there will be no take or pay obligation on the buyer.

For the ORL and ICL Gas Supply Agreements, during the Transition Period, to the extent that the Buyer has a take or pay obligation under its existing Gas Supply Agreement, the take or pay obligation will be based on a DCQ quantity of Gas representing: the difference between the buyer's consumption needs and the buyer's take or pay commitment under its existing Gas Supply Agreement, plus any make-up aggregate quantities due to the buyer under its existing Gas Supply Agreement or such higher amount notified by buyer up to the DCQ. To the extent that the Buyer does not have a take or pay obligation under its existing Gas Supply Agreement, the take or pay obligation will be based on a set DCQ.

Thereafter, IC Corporation Gas Supply Agreements collectively provide for total DCQs equivalent to approximately 2.6 BCM per annum, though certain of the IC Corporation Gas Supply Agreements permit the buyer to increase or decrease the DCQ by up to 8% up to 30 days prior to the start date if necessary in light of maximum reduction quantities under its existing Gas Supply Agreement.

Energean expects the total contract quantities for all four Gas Supply Agreements together to amount to up to approximately 39 BCM over the contract period if all conditions are satisfied.

Agreement with Supergas Natural Ltd.

Energean Israel entered into a Gas Supply Agreement with Supergas on 21 February 2018.

Subject to the terms and conditions precedent of the Gas Supply Agreement, Energean Israel agrees to sell, and the buyer agrees to purchase, natural gas during the contract period of approximately seven years from the first commercial flow of gas. The conditions precedent for the Gas Supply Agreements are, for Energean Israel, financial closing under the Senior Credit Facility and FID for development of the Group's facilities.

The Supergas Gas Supply Agreement provides for quantities of approximately 0.1 BCM per annum. Supergas may elect to increase or decrease its DCQ on an annual basis by a set percentage of the applicable DCQ per annum, with any increases subject to Energean Israel's discretion and any decreases limited to a minimum DCQ amount. Supergas may, once only during the contract period, increase its applicable DCQ by a higher percentage, also subject to Energean Israel's discretion.

Energean expects the total contract quantity of the Supergas Gas Supply Agreement to amount to up to approximately 0.7 BCM over the contract period if all conditions are satisfied.

Under the Supergas Gas Supply Agreement, Energean Israel is liable to pay delay liquidated damages based on shortfall gas for delay to commissioning.

Negotiations for further Gas Supply Agreements

Energean Israel is in continuing negotiations with additional parties regarding possible further Gas Supply Agreements.

12.3 Hedging

Historically the Group has used the following two hedging instruments:

(a) Fixed price contracts: under the BP Offtake Agreement, a fixed price is set for a specific number of barrels for a known future BP lifting to protect against (i) a fall in the oil price or (ii) the pricing optionality afforded to BP under the BP Offtake Agreement; and

(b) Zero cost collars: to provide more general downside risk protection over a longer period of time, although there is also a limit to the upside.

Between 2014 and 2016, 600,000 bbls of sales were hedged using the instruments described above. This covered approximately 28% of crude sales volume in the same period.

The gas price mechanism for the Gas Supply Agreements is predominantly based on a linkage to the Israeli electricity production component index as published by the Israeli Electricity Authority but with a small percentage (less than 5%) of the contracted quantity indexed to oil and in each case underpinned by a price floor.

13. Insurance

The Group maintains insurance coverage for its offshore facilities, onshore processing plant, operators' extra expense, physical loss or damage to Energean Force, primary and excess liabilities, support vessels hull and machinery, protection and indemnity for Energean Force and war risks for Energean Force and other vessels, in each case subject to deductibles, excesses, exclusions and limitations. The Directors believe that the Group's current insurance coverage is appropriate for its business, in respect of its level and applicable excesses and deductibles. The Group does not have any material outstanding insurance claims.

14. Competition

The oil and gas industry is highly competitive including in the region in which the Group operates. The key areas in respect of which the Group faces competition are:

- acquisition of exploration and production licences at auctions or sales run by governmental authorities;
- acquisition of other companies that may already own licences or existing hydrocarbon producing assets;
- engagement of third party service providers whose capacity to provide key services may be limited;

- purchase of capital equipment that may be scarce; and
- employment of the best qualified and most experienced skilled management and oil professionals.

See "*Risk Factors—The Group operates in a highly competitive industry*" for more detail on the risks the Group faces in relation to competition.

In Israel in particular the Group faces an increasingly competitive environment. There have been several large natural gas fields discovered in Israel in recent years and new players have been drawn to the Israeli gas market after measures taken by the government to reduce anti-competitive practices. Additionally, in Israel, the Group is licensed to sell the gas it produces only into the domestic market and gas exports by its competitors are limited. The Group therefore faces intense competition to obtain domestic gas sales contracts.

For more detail on the competitive environments in which the Group operates please see "*Overview of Israeli and Greek Oil and Gas Industry—the Israeli Gas Industry—Competitive Environment*" and "*Overview of Israeli and Greek Oil and Gas Industry—the Greek Oil Industry—Competitive Environment*".

15. Legal proceedings

The Group is involved in a number of ongoing litigation matters. Those matters which the Group believes are or may be material to the Group are summarised in "*Additional Information—Litigation"*.

See also *"Risk Factors—Risks relating to the Group's business and industry—The approval of the FDP in respect of the Karish-Tanin Development is subject to challenge"; "Risk Factors—Risks relating to the Group's business and industry—The Group's operations are subject to the risk of litigation, including risks relating to the criminal prosecution of the Group's officers and directors in the course of the conduct of their duties as part of the judicial system in Greece"; and "Risk Factors—Risks relating to the Group's business and industry—The Group may be subject to increased taxes, audits by tax authorities and liabilities in respect of historic tax periods, and the Group or certain of its employees or directors may be subject to civil or criminal liability for tax treatments arbitrarily imposed by Kavala Oil S.A."*

16. Employees

In 2016, the Group had an average of 380 personnel. Approximately 264 worked at the Sigma plant and on the offshore platforms, approximately 72 on Energean Force and marine activities, with the remaining full time employees comprising finance, legal, engineer/geology, HSE and administrative staff working in head office in Athens and the local offices in Kavala, Cyprus, Egypt and the UK.

As of 31 December 2017, the Group had 388 personnel, including four employees in its Israeli office.

16.1 Employees by location (full and part time)

Average monthly number of people employed	**For the years ended 31 December**			
Location	**2014**	**2015**	**2016**	**2017**
Israel	—	—	—	3
Greece	306	337	370	364
Cyprus	—	—	3	4
United Kingdom	—	—	1	7
Montenegro	—	—	—	0
Egypt	6	8	6	8
Total	**312**	**345**	**380**	**386**

16.2 Employees by function (full and part time)

Average monthly number of people employed	For the years ended 31 December			
Function	**2014**	**2015**	**2016**	**2017**
HSE	6	9	12	14
Drilling and production	34	53	67	70
Admin, accounting and HR	50	52	51	58
Logistics and procurement	12	16	22	26
Offshore operations	38	38	38	38
Technical	13	18	24	29
Onshore operations	61	61	61	61
E&I	28	29	31	32
Mechanical	45	43	45	48
Marine	24	27	29	10
Total Average staff numbers	**311**	**345**	**380**	**386**

16.3 Employees unions

Certain of the Group's employees are covered by collective agency agreements. 235 of the 264 employees of KOSA are covered by a collective employment agreement with expiry date 31 December 2018.

With the exception of those holding a managerial position, all employees of Energean Oil & Gas ("**EOGSA**") are covered by a collective employment agreement with expiry date 20 June 2019.

17. Dividend policy

The Directors do not expect that Energean will pay any dividends until after the completion of the development of, and first gas from, the Karish and Tanin fields, and in any event until such time as it is prudent to do so, having regard to the level of revenue generated by the Group's operations and the retained earnings to fund its operations and exploration and development programmes. Until the completion of the development of the Karish and Tanin fields, any earnings will be reinvested in developing the businesses of the Group.

PART 6
OVERVIEW OF ISRAELI AND GREEK OIL AND GAS INDUSTRY

The following information relating to the oil and gas markets in Israel and Greece has been provided for background purposes only. The information has been extracted from a variety of sources released by public and private organisations. The information has been accurately reproduced and, as far as the Company is aware and is able to ascertain from information published by such sources, no facts have been omitted which would render the reproduced information inaccurate or misleading. Investors should read this Part 6 in conjunction with the more detailed information contained in this Prospectus including Part 1 "Risk Factors", Part 5 "Business Overview" and Part 11 "Operating and Financial Review".

1. The Israeli Gas Industry

1.1 Overview

Oil and gas exploration in Israel began with the enactment of the Petroleum Law 5712-1952 (the "**Petroleum Law**") in 1952, under which several petroleum exploration companies, supported by recently established governmental institutions, were founded. Initial drilling activity yielded various small scale discoveries which had negligible production yields compared to the national consumption of hydrocarbons.

The oil and gas industry was transformed by the discovery of large off-shore gas fields, such as Noa and Mari-B (discovered by the Tethys Sea Partnership in 1999), and the major fields of Tamar and Dalit (discovered by a consortium of Noble, Avner, Delek, Isramco and Dor in 2009). One year later Delek, Avner and Ratio discovered the Leviathan structure, which is currently being developed following a final investment decision in February 2017. Noble, Avner and Delek discovered Karish and Tanin in 2011 and 2013, respectively, and Tamar Southwest in 2013. As a result of these discoveries, the Israeli Ministry of Energy considers that Israel has become a country that will, in the future, be capable of producing a substantial proportion of the energy it consumes domestically, rather than depending on imports. The Israeli government is also incentivising light industrial customers to switch from oil to gas as well as incentivising the creation of a compressed natural gas ("**CNG**") market and electric vehicles.

On the demand side, Israel has experienced an increase in demand for natural gas which is currently not met by domestic gas production. Israel is now the fastest growing gas market in the world, with natural gas consumption growing at an annual rate of 14.5% in 2016 (and at an annual rate of 15.5% over the period 2006 to 2016), according to BP's 2017 Statistical Review of World Energy. This source also estimates Israeli gas consumption at 9.7 BCM in 2016, a figure which the Ministry of Energy anticipates will rise to 18.3 BCM in 2030 and to 24.8 BCM by 2040. The main driver for this growth is expected to be an increased demand for electricity in Israel due to population growth, an increasing standard of living, greater use of water desalination, the electrification of the railway system, increased use of air conditioning, the adoption of electric vehicles and the increased use of CNG for transportation. Demand for gas in the electricity sector is expected to grow from 7.6 BCM in 2017 to 12.9 BCM in 2032 and in the transport sector from 0.0 BCM in 2017 to 2.2 BCM in 2032 with smaller increases in both the industry and distribution sector and in demand for methanol over the same period, according to the Ministry of Energy.

An additional factor inflating natural gas demand in Israel is the replacement of several coal and heavy fuel oil powered plants with natural gas powered stations, with the aim of reducing air pollution and greenhouse gas emissions. In December 2015 the Israeli Minister of Energy ordered a reduction in the usage of coal by 15% compared to the rate of usage during 2015, effective as of January 2016. In addition, the Ministry of Environmental Protection ordered an even greater reduction by IEC, which generated approximately 72% of Israel's electricity demand as of 31 December 2016, in respect of its coal power stations in Hadera and Ashkelon. IEC must reduce its usage of coal in such units by 19% each year and must close most of its coal units in Hadera (the Orot Rabin plant) by 2022 and replace the same with gas-fired generation. To further this objective, on 12 November 2017, the Minister of Energy, in accordance with his authority under the Electricity Sector Law, adopted policy principles pursuant to which priority will be given to the production of electricity using natural gas over coal, while continuing the operation of coal-based generation units in minimal load levels to enable flexibility and reliability of supply of electricity to the market. This policy is to enter into effect once the Orot Rabin coal powered units have been closed and at least three natural gas reservoirs (i.e. including Karish) have been connected to the transmission system each through a separate infrastructure. In addition, in December 2017 the Minister of Energy directed the EA to establish an initial additional quota of 300 megawatts for new natural gas fired small sized electricity production facilities to be connected to the low pressure natural gas distribution network. According to IEC's financial reports, natural gas as a percentage of fuels used by IEC in electricity

generation rose from 41.1% in 2014 to 46.3% in 2016. IEC estimated that gas accounted for 55.4% of its electricity generation in the first half of 2017. Additional gas supply to the electricity market may enable gas units to run at higher capacity factors and expedite the retirement of IEC's remaining coal units. IPPs have accounted for an increasing share of Israeli electricity generation capacity in recent years, and due to government policies to support the growth of private producers are likely to be key sources of new capacity in coming years. 2016 was the first year in which natural gas was the dominant fuel used in the production of electricity, accounting for over 50% of fuels used. The above measures will contribute to the expected increase in the proportion of natural gas in Israel's total primary energy mixture from 26% in 2014 to almost triple that amount by 2020 according to the OECD. The Directors believe that, in addition to an increase in demand for natural gas, the prolonged down-cycle in oil prices has provided access to rigs and construction resources at low rates which will allow for cost effective gas production.

Israel is projected to become a net gas exporter after the start-up of production from the Leviathan field which, according to Delek, is expected by the end of 2019 or in 2020. To this end, in 2015 the Israeli government granted export permits for a Tamar export project to Egypt and for a Tamar export project to Jordan, and to date the Tamar export project to Jordan is online (an export permit for a Leviathan export project was issued in 2017, and export by the Leviathan Lease Partners to Jordan is expected following completion of the transmission network to Jordan), and there is also potential for the export of gas to Egypt and Turkey. On 19 February 2018, Noble Energy and Delek Drilling announced the signing of agreements to export 64 BCM of natural gas from the Tamar and Leviathan fields to Egypt over ten years. Additionally, in 2017, Israel signed a declaration of intentions with Cyprus, Greece and Italy regarding the US$6 billion to US$7 billion East Med project pipeline, which would allow the export of natural gas from the Eastern Mediterranean region to Western Europe. The EU has announced that it will sponsor 50% of the pre-FEED costs of the pipeline project. By signing up to this preliminary agreement, Israel is promoting itself as a potential exporter of gas to Western Europe. The proposed pipeline would be the world's longest and deepest subsea pipeline with a targeted completion date of 2025.

While Israel has the potential to become a net gas exporter, as described above, there are currently local supply requirements imposed upon natural gas reservoirs, determined based on their size, aimed to encourage the development of smaller fields. These local supply requirements range from 50% of production for fields greater than 200 BCM down to no minimum requirements for fields less than 25 BCM.

The Israeli national transmission system is operated by INGL. INGL is a government owned corporation tasked with the construction and operation of Israel's natural gas transmission network and infrastructure under a 30 year licence, awarded by the Israeli Ministry of Energy in 2004. The transmission network currently includes four main pipelines serving the western, central, northern, eastern and southern regions of Israel and currently includes approximately 650km of pipelines. The Israeli Ministry of Energy divided Israel into six distribution licence regions and each region has a single distribution licensee, selected by public tender, who has exclusivity for the construction, operation and maintenance of the distribution network for a period of 20 to 25 years.

To accommodate the expected growth of the Israeli natural gas sector, INGL has planned the construction of additional gas facilities, the establishment of a 90 km / 36 inch pipeline between Ramle and Eliakim (which was concluded in 2017), a new pipeline to Jerusalem and the connection of various parts of the existing natural gas network. INGL is also working on the development of an additional natural gas export pipeline to Jordan (in addition to the online export project to Jordan). According to the development plan, the transmission network will be able to transmit between 10 and 15 BCM of natural gas (from the receiving terminals to customers) per year, and approximately 1.8 million cubic meters per hour.

1.2 Exploration Activity

Bidding rounds

The grant of exploration and production rights in respect of oil and gas in Israel is governed by the Petroleum Law, the Petroleum Regulations 5713-1953 and the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production) 5777-2016. The Petroleum Law allows for two processes whereby a licence may be granted, either through licence applications or through a competitive bidding process. Up until recently, exploration activity onshore and offshore Israel was conducted based on submitted applications for licence areas. To exhaust all the potential oil and gas resources offshore, the Israeli Ministry of Energy has decided to apply the process of competitive bid rounds to applications for all resources in the Israeli EEZ, and the first bidding round of 24 blocks that are located in the central part of the offshore area was launched in November 2016 and concluded in November 2017.

The Israeli EEZ in the Mediterranean Sea is divided by the Israeli Ministry of Energy into 69 exploration areas or blocks. Each block has a maximum size of 400km^2, as required by the Petroleum Law. The block pattern takes

into account existing licences and leases that were previously granted through applications, therefore some of the new exploration areas are smaller and irregular in shape. The Israeli Ministry of Energy is planning to conduct a second bidding round for new exploration areas in the EEZ during 2018.

Geological Setting and Hydrocarbon Plans

The Israeli EEZ occupies the central part of the Levant Basin. This deep marine basin, where water depth reaches up to 2,000m, is located in the south-eastern part of the Mediterranean Sea, surrounded by the land masses of Egypt, Israel, Lebanon, Syria and Cyprus. The unique geologic history of the Levant Basin is associated with the existence of various types of petroleum systems and hydrocarbon plays. The Oligo-Miocene play includes the giant fields of Tamar and Leviathan where biogenic gas was found in thick succession of deep marine sedimentary sands. Smaller but significant amounts of biogenic gas were found in younger, Pliocene sediment sands in the partly explored Upper Miocene/Pliocene play.

The hydrocarbon potential of these plays has been evaluated with estimated unrisked prospective resources of 7,023 BCM of gas and 26 Billion bbls of oil (P50 best guess); and risked prospective resources of 2,137 BCM of gas and 6.6 Billion bbls of oil (P50 best guess) in the Levant basin according to the Israeli Ministry of Energy.

1.3 Competitive Environment

There is no national oil and gas company in Israel and prior to the offshore discoveries made in recent years the majority of the oil and gas companies operating in the Israel were domestic. In 1998 Noble Energy entered the country and over the years it was able to increase its holding of operating licences to 14 and gain a leading position in the Israeli offshore sector.

Following Noble's success, several international companies acquired exploration acreage including AGR Group and ATP Oil and Gas Corporation. The main domestic oil and gas companies operating in Israel include Delek, Ratio, Dor and Isramco.

Currently all of Israel's natural gas production, and the majority of its condensate production, is attributed to the Tamar field which is owned by Noble, Isramco, Delek, Everest and Dor.

Due to the fact that Noble and Delek held a significant proportion of the interests in Israeli oil and gas discoveries, the Israeli government felt that a threat to competition in the Israeli energy market had emerged. Therefore, the Israeli government introduced various legislative measures to break up the Noble and Delek duopoly and to foster competition. One such measure was the Natural Gas Framework ("**NGF**") which contained a requirement that Karish and Tanin be sold to a non-associated party which resulted in Energean acquiring the two fields. For more detail on the NGF see "*Regulatory Overview—Regulatory and legislative framework in Israel—Government Regulations—Competition with the Upstream Natural Gas Duopoly*".

The Israeli Ministry of Energy is currently promoting the rapid development of gas fields and is seeking to expand offshore exploration and production activities as demonstrated by the 24 licence blocks offered in the first Israeli Offshore bid round. See also Part 6 "*Overview of Israeli and Greek Oil and Gas Industry—the Israeli Gas Industry—Exploration Activity—Bidding Rounds*".

2. The Greek Oil Industry

2.1 Overview

Oil exploration in Greece dates back to at least 1903 with the first wells drilled by companies such as the London Oil Development Company, Hellis and Pan-Israel. These first companies were chiefly drilling offshore in the Island of Zakynthos, the Peloponnese and Evros. Exploration efforts during this early period were mainly focused on onshore areas with evidence of surface oil seepage.

In the 1960s and 1970s, exploration became more systematic, requiring the establishment of the first public body oriented to the exploration of hydrocarbons. Run by the former Ministry of Industry, in collaboration with the Institute of Geology and Mineral Exploration and in consultation with the Institute Francais du Petrol, extensive geological research was carried out in continental Greece, and 17 shallow depth wells were drilled.

At the same time, concessions were granted to major companies, such as BP (Aitoloakarnania area), Esso (Northwest Peloponnese, Zante and Paxi islands), Hunt Oil Company (Thessaloniki), Texaco (Thermaikos gulf), Chevron (Limnos island), Anschutz Exploration Corporation (Thessaloniki-Epanomi) and Oceanic-Colorado (Thracian sea), which drilled, in total, more than 40 wells, both on- and offshore. Most of the former wells penetrated geological targets that gave, in some cases, encouraging hydrocarbon indications and contributed significantly to the geological data available and drew interest in the hydrocarbon potential of the country.

An additional outcome of the exploration that took place during that time was the discovery of the first exploitable hydrocarbon reserves in the offshore area of Thasos Island. These areas, the Prinos basin and the South Kavala gas-field, are currently owned and operated by Energean.

Energean is currently the only company in Greece operating producing assets. The rest of the domestic industry is focused instead on refining and distributing oil and oil products. In terms of global oil production Greece remains a relatively minor player.

In 1996, Greece undertook a International Licensing Round, involving 6 concession areas. As a result of the first international licensing round, 4 licences were granted. Northwest Peloponnese and Ioannina were licensed to Enterprise Oil and Aitoloakarnania and offshore Western Patraikos Gulf were licenced to Triton Ltd. The total amount of investment in seismic surveys and drilling at this time reached approximately €85 million.

These initial surveys failed to identify significant resources and well drilling did not reach the depth prescribed by the original licences. However, two important targets were not investigated. In Ioannina, deep drilling was abandoned due to serious technical problems encountered by Enterprise Oil. In the Western Patraikos Gulf, the planned drilling program was not executed because of the acquisition of Triton Ltdl by Amerada Hess. The companies both withdrew from their Greek licences in the early 2000s.

After those withdrawals, almost no exploration activity was undertaken for the next decade. The end of this drilling activity, however, marked the beginning of a concerted effort by the Greek government to reform the legal framework governing the granting of hydrocarbon exploration and exploitation licences.

In 2007, following an amendment added in law 3587 (article 20), the Greek government recalled all concession areas formerly granted apart from those in which Hellenic Petroleum participated in the Prinos area.

The former legal framework surrounding the procedure for granting exploration/exploitation rights was reformed, by the new law 4001/2011. The focus of the reforms was to create a new attractive entrepreneurial environment in the Greek oil and gas industry. In 2014, the Greek government opened a tender process for hydrocarbon exploration rights, which included 20 different areas. Of the available leases in the 2014 round, Energean bid for three with the remaining 17 receiving no bids.

While Energean is the only company currently producing oil offshore in Greece, there has been a growing amount of interest from other international oil and gas companies. Currently, Greece has received interest for hydrocarbon exploration and exploitation in two sites off the coast of Crete from a consortium of Exxon Mobil, Total and Hellenic Petroleum. Firmer crude oil prices and a more stable political climate in Greece are expected to attract prospectors to the remaining 17 blocks in the Ionian Sea and south of Crete according to the Hellenic Hydrocarbons Resources Management ("**HHRM**"). HHRM has been tasked with finding investors, overseeing licences and monitoring the implementation of exploration and exploitation agreements.

Oil and gas consumption

According to the European Commission's energy statistics datasheet, Greece produced 0.1 MMtoe of petroleum products in 2015. However, in the same year Greece imported 31.4 MMtoe of petroleum products.

While its total production volumes put Greece behind other oil producing European nations, there is sufficient demand to support significant future growth in Greek oil production. Between 2006 and 2016 European Union member states decreased their consumption of crude oil by 14.7% and Greece reflects this trend with a fall of 27.9% in that same period. Natural gas consumption, which decreased across the European Union by 12.5%, decreased in Greece by 9.7% during that same period. According to the European Commission's energy statistics datasheet, Greece produced a minimal amount of natural gas in 2015, but in the same year imported 2.7 Mtoe of natural gas suggesting robust domestic demand.

Macroeconomic Impacts

The economic recession that hit Greece in 2009 had a considerable impact on the demand for energy. Households and businesses reduced their energy consumption in order to reduce energy costs causing a 30% reduction in energy consumption during the 2008-2013 period. Since 2013, energy consumption has increased slightly from 24.2 MMtoe in 2013 to 24.4 MMtoe in both 2014 and 2015 (although this is still down from 31.4 MMtoe in 2005). The decrease in energy consumption in the period following the economic recession was caused mainly by a reduction in consumption of both petroleum products and electricity.

The Greek oil industry is one of a number of domestic industries identified by the EBRD as a means of supporting the overall Greek recovery.

Future pipeline development

There are currently three major pipeline projects which would traverse Greece. The Trans-Anatolian pipeline is planned to run from the Turkish border with Georgia, across 20 Turkish provinces, before ending at the Greek border in the Ipsala district of Edirne. Here the pipeline will connect to the Trans-Adriatic pipeline, which is planned to run 550km across Greece from the border with Turkey in Kipoli to Albania in the west. Finally, the Eastmed pipeline is a 1,700km long pipeline which is planned to run from the Levantine basin (Israel) to Cyprus then to Crete, Peloponnesus and finally offshore to connect with the Poseidon pipeline to Italy.

In addition, a floating gas storage and regasification unit offshore Alexandroupolis designed to transmit natural gas into the Greek national natural gas system is expected to begin operations in 2020, creating a fourth natural gas import route to Greece. The LNG terminal Revythoussa has also undergone upgrades in recent years.

2.2 Exploration Activity

Energean has a substantial portfolio of exploration projects located in the Aegean and western Greece. These assets include acreage in the Ionian Zone which is considered to be part of the southern-most extension of the greater peri-Adriatic basin, which has proven productive for oil and gas in Albania, Italy and Croatia.

Other parties have begun showing a greater interest in the Greek oil and gas market. Repsol signed an agreement to buy a 60% stake of a concession contract for hydrocarbon explorations in the regions of Ioannina and Aitoloakarnania from Energean. Under the terms of the agreement, Repsol will take over as operator and will proceed with a seismic search in the Ioannina field in the period 2017/2018 and in Aitoloakarnania in the period 2018/2019.

Also, in June 2017, the Greek Minister for the Environment and Energy, following a recommendatory note by HHRM, accepted an expression of interest submitted in May 2017 byTotal, ExxonMobil and Hellenic Petroleum regarding offshore exploration and exploitation to the southwest and west of Crete.

On 2 June 2017, Energean submitted to HHRM an expression of interest in the exploration and exploitation of hydrocarbons in the Ionian block, a maritime area to the west of Greece.The Minister for the Environment and Energy, following a recommendatory note by HHRM, subsequently accepted such expression of interest and initiated the tendering procedure on 2 December 2017.

2.3 Competitive Environment

The Greek oil industry is relatively small. Energean has historically been the only hydrocarbon producer in Greece and there are only two companies currently operating in the Greek refining industry, Hellenic Petroleum and Motor Oil Hellas. The Greek state owns 35.5% of Hellenic Petroleum but the company is expected to be fully privatised in the coming years.

In June 2017, HHRM tenders were initiated after a joint venture of Total, Edison and Hellenic Petroleum was named as the selected applicant for a block offered in the second Greek licensing round located offshore western Greece. The entry of these major oil and gas players is indicative of increasing activity in the Greek oil and gas industry.

PART 7
REGULATORY OVERVIEW

1. Regulatory and legislative framework in Israel

1.1 Government Regulations

The natural gas sector in Israel is regulated by two primary laws: the Petroleum Law and the Natural Gas Sector Law 5762-2002 (the "**NG Law**").

While the Petroleum Law establishes the legal framework governing the upstream exploration and production of oil and gas, the NG Law regulates the downstream natural gas sector. The Petroleum Law establishes procedures for granting preliminary permits, licences and leases ("**Petroleum Rights**") and governs both onshore and offshore activities in connection with Petroleum (broadly defined by the Petroleum Law as: "any petroleum fluid, whether liquid or gaseous, and includes oil, natural gas, natural gasoline, condensates and related fluid hydrocarbons, and also asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum"). By contrast, the NG Law governs natural gas infrastructure, including distribution, transmission, storage and LNG facilities and sets out the licensing regime for such infrastructure. The NG Law applies only to natural gas.

The principal regulatory body in Israel's energy sector is the Israeli Ministry of Energy, which is headed by the Minister of Energy. The Israeli Ministry of Energy's Natural Resources Administration houses the Petroleum Unit (overseeing upstream activities and headed by the Petroleum Commissioner who oversees Petroleum exploration and production activities as well as issues the various types of Petroleum Rights). The Israeli Ministry of Energy also houses the Natural Gas Authority, which regulate the infrastructure governed by the NG Law and are responsible for granting of licences, setting the tariffs and determining service rules for such infrastructure.

The NG Law

In order to enable the operation of natural gas infrastructure, a licence must be issued to the following: the construction and operation of a transmission system; a storage installation facility; a LNG facility (defined as a regasification import facility); and a distribution network. However, the marketing and sale of natural gas does not require a licence unless the Israeli Minister of Energy, in prescribed circumstances and for a limited period of time, determines it to be necessary. (All terms in this sub-section are as defined in the NG Law.)

The Petroleum Law

Since petroleum resources belong to the State of Israel, the Petroleum Law requires that in order to conduct exploration and production activities, one of three types of rights must be granted: two relevant to the exploration stage (the preliminary permit and licence, respectively), and the third for production (the production lease).

Upon a "discovery" of Petroleum in commercial quantities during the term of a licence, the licensee has a statutory right to receive a production lease. Petroleum leases may cover an area of up to 250 square kilometres and are granted for an initial term of 30 years, extendible to a maximum of 50 years in total. The Karish and Tanin leases have been granted until 10 August 2044.

The rights of a lessee under the Petroleum Law include the exclusive right to explore and produce Petroleum in the lease area; the right to process, transport, export, import and trade in Petroleum and Petroleum products and to install facilities for these purposes; the right to construct pipelines for the transport of Petroleum and Petroleum products and install other facilities required according to the plans and route approved by the Petroleum Commissioner.

The Petroleum Law places certain obligations on a leaseholder, including timetables for the commencement of the drilling of a development well and for the commercial production of Petroleum.

Petroleum Rights and their transfers and pledges are registered by the Petroleum Commissioner in the Petroleum Registry in accordance with the Petroleum Law.

According to the Petroleum Law, Petroleum Rights, and any benefit therein, are individual and their transfer and/or encumbrance are subject to the approval of the Petroleum Commissioner after consultation with the Petroleum

Council. After several years of changes to the rules regarding the transfer of Petroleum Rights and benefits therein, final guidelines establishing the rules, requirements and conditions applicable to the transfer and encumbrance of such rights and the relevant approval process were published by the Petroleum Commissioner in December 2015.

The Marine Bill

In recent years, the Israeli government has been working on legislation to eradicate the uncertainty surrounding application of local laws outside Israel's territorial waters, in the Israeli EEZ, where both the Karish and Tanin Leases are located. In December 2014, the Israeli government published the Marine Areas Bill-2014 (the "**Marine Bill**") which, when legislated, seeks to create certainty by determining a "closed list" of local laws that apply in the EEZ. An updated version of the Marine Bill has been formally published in November 2017 and submitted to the Israeli Parliament and has recently passed the first out of three votes, and is currently being prepared for the second and third parliamentary votes. The current draft of the Marine Bill explicitly applies the Israeli tax, health and safety and environmental laws in the EEZ, including the Restrictive Trade Practices Law (1988) and Natural Gas Sector Law (2002), and further applies immigration labour and employment laws to "Permanent Marine Installations" (as defined in the Marine Bill).

Competition with the Upstream Natural Gas Duopoly

In response to the emergence of a duopoly over offshore natural gas discoveries, the Israel Antitrust Authority ("**IAA**") issued a number of decisions regarding long-term Gas Supply Agreements signed between Noble, Delek, Avner, Isramco and Dor (the "**Tamar Lease Partners**") and private electricity producers and the Israel Electric Company. The decisions issued in 2012 regarding private electricity producers required their Gas Supply Agreements to include an obligation placed on the Tamar Lease Partners to offer gas consumers under these Gas Supply Agreements the opportunity to notify Tamar regarding a reduction of gas quantities within a specified three-year window. These decisions were supplemented by an additional IAA decision issued on 27 December 2015 applicable to nine long-term Tamar Gas Supply Agreements, and obligated the Tamar Lease Partners to offer these gas consumers an opportunity to notify Tamar regarding a reduction of quantities within a specified three-year window. The IAA decisions permit this set of consumers to reduce the ACQ under their Tamar Gas Supply Agreements to a quantity equal to 50% of the average ACQ consumed in the three years prior to the date of the consumer's notification regarding its desire to reduce quantities.

In 2015, an inter-ministerial task force was appointed, in order to reach a comprehensive agreement addressing several outstanding regulatory and antitrust issues in respect of the duopoly. The taskforce's efforts resulted in the NGF struck between the government, Noble and Delek.

The NGF's core principles include requiring Noble and Delek to transfer their rights in the
Karish and Tanin reservoirs within a set time period, as well as to dilute and transfer their rights in the Tamar reservoir within a set time period; establishing a termination flexibility and determining a set price mechanism to be proposed for new Gas Supply Agreements signed by the Tamar and Leviathan leaseholders, within a set time period; adopting a broad stability clause; establishing milestones and incentives for the development of the Leviathan field; and clarifying the export allowance from the Tamar field. The NGF was initially approved in August 2015; however, following a decision of the Israeli High Court of Justice rejecting the stability clause, the government, Noble and Delek reached an agreement regarding a revised stability clause in May 2016, allowing for the implementation of the NGF.

Recent Protection Measures

Infant industry protection measures for small and medium-sized fields, primarily for the benefit of the Karish and Tanin fields, were introduced in April 2017 for the further development of the natural gas market in Israel. The bulk of these measures are included in the Protection Decision (Government Decision 2592) and are supplemented by back-up regulations (Conduct of Natural Gas Market During a National Emergency, 5777-2017) (the "**Back-Up Regulations**") and other regulatory decisions. The Protection Decision introduced, for the first time, back-up regulations to address circumstances of the non-supply of gas by a gas supplier, during which the other suppliers are required to provide back-up gas. These regulations were approved as part of the Protection Decision and subsequently published with the aim of enhancing security of supply in the natural gas market.

According to the Protection Decision, the Minister of Energy is instructed to declare a state of emergency in accordance with Section 91(a) of the NG Law, after receiving Government approval, in the following

circumstances: (a) where the supply to the local market relies only on Tamar reservoir – if it is expected that during the next business day the maximum delivery quantity obtainable from Tamar in a certain hour is less than 75% of the maximum quantity the Tamar reservoir is supposed to deliver and (b) where at least one more field is connected to the national transmission system (and not through the Tamar pipeline) and a supplier (Tamar and any significant fields specifically including Karish, Tanin and Leviathan) cannot supply gas to the transmission system and as a result of such inability during the next business day it is expected that: (i) the maximum supply which can be supplied during the peak hour to the local market is less than 85% of the quantity the local market usually consume; or (ii) the maximum supply obtainable during a certain hour from one of the fields is less than 20% such field is supposed to provide. The Back-Up Regulations enter into force when a "state of emergency" has formally been declared by the Minister of Energy, with the approval of the government as detailed above.

The Back-Up Regulations determine two sets of rules for the operation of the local natural gas market during a declared state of emergency: one which applies when 90% of the gas supply to the local market is supplied from one field which is connected to the national transmission system (i.e. the current situation where the local market relies only on Tamar reservoir) and the other which applies when the local market is supplied from at least two fields which are connected to the national transmission system.

When only one field supplies the local market, the The Back-Up Regulations determine rules for allocation of gas during a state of emergency which include securing a certain amount to "distribution network consumers" (mostly industrial plants) and giving preference to home consumers, and rules for allocation of LNG to be supplied by the IEC.

When at least two fields supply the local market through the transmission system, the Back-Up Regulations determine the details of a mechanism under which gas suppliers will be obligated to offer any Excess Gas (as defined therein) for sale to a Gas Supplier in Failure (as defined therein) and determine that where gas suppliers cannot agree on a price for the back-up gas, the gas supplier must sell the gas at a price according to the average price in the market as published every quarter by the Natural Gas Authority. Furthermore, the Back-Up Regulations determine the rules for allocation of "back-up gas" purchased by the Gas Supplier in Failure which include securing a certain amount to "distribution network consumers" (mostly industrial plants) and giving preference to residential consumers.

Section 8 of the Back-Up Regulations allows the Minister of Energy to deviate from the allocation rules set under the Back-Up Regulations, including with respect to the allocation of LNG by the IEC, in certain extreme scenarios as determined in the regulations. Such scenarios include situations where the lack of gas extensively harms the regular functioning of the local market or the regular supply of electricity to the Israeli market.

On 11 September 2017, the Minster of Energy, following the approval of the government, declared a state of emergency, for the period commencing on 19 September 2017 and ending on 31 October 2017. This was due to maintenance works in the production system of the Tamar reservoir, during which time the gas supply from Tamar was limited to 50%.

Further to the 11 September 2017 declaration of a state of emergency, on 21 September 2017, while carrying out the maintenance works in Tamar platform a crack in the exhaust pipe used on the Tamar platform to release natural gas and pressure was discovered resulting in an immediate halt of all gas supplies from Tamar. Due to the complete cessation of gas supply from Tamar, the Minister of Energy used his authority under Section 8 of the Back-Up Regulations and published on 21 September 2017 instructions for the allocation of LNG (which were updated on 23 September and 24 September), which included exact quantities to be secured to each industrial consumer and residential consumers with the remainder to be allocated to electricity producers according to the market needs and taking into consideration that the LNG existing in the LNG container should meet the local market needs until 2 October 2017. These special instructions (which deviated from the general allocation rules) expired on 28 September 2017 after the crack in the Tamar platform exhaust pipe was fixed.

Under the Protection Decision, the last approximately 10km of the pipeline to connect the Karish-Tanin Development to the national transmission system could be constructed and operated by INGL. The Protection Decision also allows for INGL to construct and install the pipeline by means of "the first leaseholder of a small or medium field in that area" (i.e., Energean Israel Limited). Accordingly, the Group and INGL are in the final stages of negotiating the principles regarding the last approximately 10km of the gas pipeline which is planned to be transferred to, and operated by, INGL following start-up of production from the FPSO, following its construction by Energean Israel.

As mentioned above, according to the NG Law, construction and operation of a transmission system (such as the Group's planned pipeline up to the connection point with the national transmission system operated by INGL), requires a transmission licence under article 10 of the NG Law.

As per the NG Law a transmission licence can only be granted to a company which is incorporated in Israel and accordingly, EISL is currently establishing a wholly owned Israeli subsidiary, for this purpose.

In addition, subject to certain conditions, the Protection Decision determines that the government shall invest 100 million ILS as part of financing the construction of such offshore pipeline and that regarding the additional cost of such pipeline (exceeding the 100 million ILS), the Natural Gas Authority Council intends (as noted in the Protection Decision) to approve a decision under which these costs will be paid by all natural gas buyers in Israel via the transmission tariff, subject to certain conditions. On 21 November 2017, the Natural Gas Authority Council issued its decision for updating the transmission tariffs as of 1 January 2018, in order to finance the expansion of the national transmission system, inter alia, through the construction of such approximately 10km offshore pipeline as per the Protection Decision. In its decision, the Natural Gas Authority Council indicated that the total cost of said offshore pipeline is estimated at 386.3 million ILS, and that the 286.3 million ILS exceeding the government's investment (of 100 million ILS) in accordance with the Protection Decision, approved for finance through the increase of the transmission tariffs, will be funded by INGL through the issuance of bonds. The Natural Gas Authority also stated in its decision that following the completion of the offshore pipeline, the actual costs will be examined, and if required the transmission tariff may be updated.

Regulatory Framework for Conventional IPPs

The regulatory framework for currently operational IPPs (such as Dalia and Dorad) was set by the Israel Electricity Authority through both the Electricity Sector Regulations (Conventional Private Electricity Producer) 2005 (the "**Conventional Regulations**") and a decision of the Israel Electricity Authority in 2008 as amended from time to time. According to the Conventional Regulations, IPPs are entitled by the regulatory framework to long-term power purchase agreements ("**PPAs**") with purchase guarantees by the system manager (currently IEC). An IPP may choose to designate its generation capacity as "permanently available capacity" ("**PAC**") or as "variable available capacity" ("**VAC**"). An IPP may choose to allocate its capacity between 70% and 90% as PAC with the remaining 10% to 30% as VAC, or 100% VAC. PAC means capacity that is allocated exclusively to the system manager (IEC), and is dispatched according to the system manager's instructions. PAC receives regulated capacity payments for the capacity allocated to the system manager (to the grid), as well as energy payments to cover the energy costs, in the event that the unit is dispatched. Both PAC and VAC values are set by the regulator, based on a "normative" costs model of a "best entrant" IPP. This is true for both the CAPEX and OPEX costs, and the normative rate of return. This regulation was set in the absence of a market-based electricity wholesale mechanism in Israel. VAC refers to capacity that is allocated to private consumers, and sold according to a bilateral agreement between the IPP and a third party. An IPP may sell VAC capacity to IEC on a short-term basis. IEC may purchase electricity from the VAC allocated to it, based on a regulated price proposal by such IPP, which cannot be higher than a normative price prescribed in the Electricity Authority's regulations. This regulatory framework also guarantees the repayment of the natural gas costs under the gas contracts (regarding capacity sold to IEC) after approval by the Israel Electricity Authority as part of the energy payment component. In addition, the IPPs have priority in energy dispatch in order to follow their bilateral consumers' load profile, in a physical load following manner. According to this regulatory scheme, the IPPs also enjoy regulatory protections of their financial debts in cases of force majeure, as defined in the Electricity Authority's regulations (mainly in the cases of war and terror), in order to encourage investments. The above-mentioned regulatory scheme was applied to the first IPPs who reached financial closing and were operational before 2016, up to a limited quota set by the Israel Electricity Authority.

In December 2014, the Electricity Authority published a new "second phase" regulatory framework for conventional IPPs with installed capacity of 16 MW or more, which applies to conventional IPPs who shall receive a tariff approval no later than 1 January, 2020. The new framework, which was updated in June 2015 and May 2017, allows an IPP to choose between a transaction with IEC (similar to PAC regulation), and a bilateral agreement with a third party. However, a combined cycle IPP must allocate at least 15% of its capacity to a bilateral agreement with a third party. An IPP may sell to IEC energy that was allocated to a third party on a short-term basis and based on a "system marginal price" (as set by the Israel Electricity Authority).

According to the latest update to the regulatory framework dated May 2017 such regulatory framework shall apply to new IPPs who receive their tariff approval by January 2020 subject to the following quota: at least 450 MW and up to 700 MW for combined-cycle facilities and at least 400 MW and up to 650 MW for open-cycle flexible facilities (peakers).

This second phase conventional regulation differs from the first one discussed above in the sense that it establishes an economic dispatch mechanism of energy, managed by the system manager unit at IEC. There is no longer a physical load following prerogative to the IPP, but rather an all economic dispatch system, while bilateral agreements between IPPs and consumers are financial.

Regulatory Framework for Cogeneration IPPs

The regulatory framework for current and under construction cogeneration IPPs was established by the Israeli Electricity Authority in its 2008 and 2013 decisions (updated in December 2015 and December 2016) regarding IPPs with installed capacity of 16 MW or more and by the Electricity Sector Regulations (Cogeneration) 2004 (the "**Cogeneration Regulations**"). The primary difference between the regulation of cogeneration IPPs (as compared to the regulation of conventional IPPs) is that, as long as the cogeneration production unit meets the definition of a "Cogeneration Production Unit" as stipulated in the Cogeneration Regulations (which require such unit to, among other things, meet a certain efficiency rate), and if the cogeneration IPP so wishes, IEC will be obliged to purchase energy from such IPP (as a safety net) in accordance with the following provisions:

1. At peak and shoulder hours, one of the following shall apply:
    a. each year, the IPP may sell up to 70% of the total electrical energy, calculated annually, produced in its facility to IEC—for up to 12 years from the date of the grant of the licence; and
    b. each year, the IPP may sell up to 50% of the total electrical energy, calculated annually, produced in its facility to IEC—for up to 18 years from the date of the grant of the licence.
2. At low demand hours, IPPs with units with an installed capacity of up to 175 MW, may sell electrical energy produced by it with a capacity of up to 35 MW, calculated annually. IPPs with units with an installed capacity of above 175 MW may sell up to 20% of the total electrical energy, calculated annually, produced in its facility to IEC. This arrangement shall apply during the same period of the alternative chosen by the IPP under section 1 above regarding the peak and shoulder hours.

The aforementioned purchase obligation of IEC shall apply only to power plants that received a provisional licence for electricity generation by January 1, 2015, and on the basis of which received a permanent licence for generation by July 1, 2020.

According to decisions published by the Electricity Authority in January and December 2015, if a cogeneration facility no longer qualifies as a "Cogeneration Production Unit," such cogeneration facility may be entitled, under certain circumstances, to operate under the regulatory framework for conventional IPPs which provides for much lower commitments of IEC to purchase energy offered to it by such IPP (for example there is no obligation of IEC to purchase energy during low demand hours), with certain modifications and limitations. With respect to cogeneration IPPs which did not complete their financial closing (and received a tariff approval) by January 2015, such IPPs will be entitled to a less favourable arrangement with lower availability payments for capacity made available to IEC together with a very low cap on the tariff for such availability during the first 4 years of operation and with an additional cap on the price to be paid for energy actually transferred to IEC.

The Electricity Authority's decisions regarding cogeneration IPPs expired on 30 June 2017. However, they remain in force with regards to the cogeneration IPPs that received tariff approval from the Electricity Authority while the decisions were in force.

1.2 Fiscal Regulations

Israel has imposed a specific royalty regime on the exploitation of oil and natural gas. Its key elements are a royalty of 12.5% imposed, in accordance with the Petroleum Law, on petroleum and natural gas according to their market value at the wellhead.

In addition, and following the recommendations of a governmental committee in 2011, the Israeli Parliament passed the Taxation of Profits from Natural Resources Law (2011) (the "**PNR Law**"). The Levy imposed under the PNR Law is imposed in addition to the 12.5% royalty to the state as per the Petroleum Law, but is deductible for income tax purposes under section 17 of the Ordinance. The PNR Law imposes a progressive levy on Petroleum Profits derived from a Petroleum Project (the "**Levy**"). Petroleum profits are defined as the difference between the Current Revenues and the Current Payments in each year (all capitalised terms herein refer to defined terms in the PNR Law).

The Levy is imposed on the Petroleum Profits of a Petroleum Project (in principle, the joint venture that is comprised of the owners of the Petroleum Right), ring-fenced by a single Petroleum Right. The Levy is calculated dynamically by comparing receipts to payments and compared to the level of investment made. The Levy is imposed at the rate of 20% once the cost recovery ratio of the Petroleum Project has reached 150% (as calculated under the PNR Law) and is gradually increased up to a ceiling rate of 50% when the cost recovery ratio of the Petroleum Project reaches 230%. Note that the ceiling of 50% may be reduced with a certain formula

(as described below) when the corporate income tax exceeds 18%. Unless specifically approved by the Israeli Tax Authority ("**ITA**"), the shifting of revenues or investment costs from one Project to another is not allowed for the purposes of calculation of the Levy.

The PNR Law contains a detailed formulaic definition as to how the Levy is calculated.

Royalty payments are deducted from Petroleum Profits for the calculation of the Levy and also included in Cumulative Current Payments in the numerator of the Levy ratio. In addition, royalties are deductible for corporate income tax purposes in the year incurred under section 17 of the Ordinance.

Under the Law, if corporate tax rate will be higher than 18%, the maximum monthly levy rate will be 50% less 0.64 multiplied by the difference between the actual corporate tax rate and 18%. Since the corporate tax will be 23% (from 2018 onwards), the maximum monthly levy rate will be approximately 46.8%.

The Israeli Income Tax Ordinance 5721-1961 (the "**Ordinance**") imposes tax upon the worldwide income of Israeli residents (including Israeli branches of foreign companies) and the Israeli sourced income of foreign residents. Thus, petroleum exploration and production activities carried out in Israel are subject to tax under the Ordinance, whereas the corporate tax rate in Israel is 23%.

Under the PNR Law, Fixed Assets are depreciated under one of two alternative methods: (i) a straight line depreciation method with a fixed rate of up to 10%; or (ii) a changing rate such that the overall depreciation of Fixed Assets under this method will be equal to the taxable income but with a cap of 10% of the Fixed Asset cost base, at the choice of the oil right holder. Fixed Assets include machines, equipment, exploration and development expenses including expenses for examinations, geological, geophysical, geochemical and similar tests, except for real estate. Depreciation commences in the year commercial production starts.

Energean Israel has obtained a written ruling by the Israeli tax authorities according to which the acquisition cost of Karish and Tanin will be amortised with the following structure, the initial payment US$40 million has a 10% depreciation straight line and the outstanding consideration of the US$108.5 million has a depletion method, which applies the 1P reserves in the denominator of the ratio. The starting point of the depreciation will be the date of commencement of production.

1.3 Health, Safety and Environmental Regulations

The Petroleum Regulations include general conservation and safety provisions designed to ensure the health, safety, and welfare of those engaged in Petroleum exploration and production activities. The Petroleum Regulations further address, inter alia, precautions to be taken to prevent the uncontrolled flow of fluids between geological formations; establishment of maximum efficiency rates and the Petroleum Commissioner's ability to regulate these; and pressure maintenance provisions. Throughout 2016, the Natural Resources Administration published a number of guidelines and rules regarding environmental and safety requirements for the exploration and production of offshore Petroleum, which instruct offshore Petroleum Rights holders what actions they are required to take and which safety measures should be maintained.

The exploration and production process might be subject to Israeli labour and employment laws in order to maintain employees' rights while on the FPSO or the drilling rig (subject to their classification as a Permanent Marine Installation under the Marine Bill).

1.4 Israel's First Bid Round for New Licences

In November 2016, the Israeli Minister of Energy announced the re-opening of the Mediterranean Sea for oil and gas exploration, presenting an independent research study conducted for the MOE which estimated the quantity of undiscovered gas off Israel's shores at approximately 2,100 BCM. The exploration rights are to be awarded via a bid round. The first bid round announced on 15 November 2016 consisted of 24 search zones with a maximum area of 400km^2 each. The bid was concluded on 15 November 2017, with awards announced 12 December 2017. See *"Business Overview—Overview of Assets—Israel—Blocks 12, 21, 22, 23, 31"* and "*Overview of Israeli and Greek Oil and Gas Industry—The Israeli Gas Industry—Exploration Activity—Bidding Rounds*" and *"Operating and Financial Review—Current Trading and Prospects"*.

2. Regulatory and legislative framework in Greece

The oil and gas industry in Greece is governed by many statutes and subsidiary legislation, with the most relevant being Law 2289/1995 (the "**Hydrocarbons Law**"). The Hydrocarbons Law, and the regulations made pursuant to it, has established a legal framework for the regulation of the petroleum industry in Greece.

2.1 Government Regulations

The Ministry of Energy's (formerly the Ministry of Energy, Environment and Climate Change, which was recently absorbed by the Ministry of Reconstruction of Production, Environment & Energy) intention is to provide and support a business friendly environment and attract new investors. Hellenic Hydrocarbons Resources Management was thus formed as a totally independent, corporate entity, whose articles of association are already published in the form of a Presidential Decree, and whose board of directors has been selected through the transparent open government process, which will undertake the responsibility to organise and execute all the relevant exploration and/or production tenders, evaluate the offers, select the first preferred bidders, prepare the relevant agreements and supervise their appropriate execution.

2.2 Exploration and production regulations

Hydrocarbons Law

The Hydrocarbons Law, as amended, is intended to improve the framework for the commercial exploration and development of hydrocarbon deposits in Greece and to make Greek oil and gas industry investment opportunities more attractive.

The Hydrocarbons Law governs the prospecting, exploration and exploitation of hydrocarbons in Greece. The major industry terms used by the Hydrocarbons Law are defined as follows:

- Hydrocarbons—All oil products found in solid, liquid or gaseous form. In particular, this includes mineral crude oil and natural hydrocarbonated gas as well as all kinds of minerals and substances found with them.
- Prospecting—The attempt to locate hydrocarbons in a specific area by an appropriate method other than drilling.
- Exploration—The discovery of hydrocarbon deposits by any appropriate method including drilling.
- Exploitation—The extraction of hydrocarbons, any treatment which is necessary to make them marketable and their storage and transportation to the loading installations for further disposal. Any treatment referred to in this paragraph does not include refining.

Chapter A (Article 2.1) of the Hydrocarbons Law, entitled "*Exercise of Rights by the State*", indicates that the rights of prospecting, exploration and exploitation of hydrocarbons belong exclusively to the Greek State and the State must exercise those rights for the public benefit.

With the creation of HHRM, the State's rights of prospecting, exploration and exploitation of hydrocarbons have been assigned to HHRM. Consequently, in order to be granted the right to prospect for hydrocarbons, a decision needs to be made by HHRM according to the procedures provided by paragraph 17 of Article 2 of the Hydrocarbons Law.

The Hydrocarbons Law provides for (a) the right of exploration and exploitation to be conceded by the State to interested parties by way of a tendering process; (b) two types of concessions may be granted, one for leasing and another for production sharing; (c) the duration of exploration to be up to seven years onshore and up to eight years offshore with the possibility of extension; term extensions for exploration are only allowed when unpredictable technical obstacles occur or the commercial viability of the deposits found requires further testing. On the expiration of the exploration period, any installations must be removed and sealed and the site must be restored within six months; and (d) the exploitation period lasts 25 years, starting from the notice of discovery of profitable deposits. Time extensions to the exploitation period may be allowed.

The process for the tender of rights for the exploration and exploitation of hydrocarbons in Greece under the Hydrocarbons Law (Chapter A, Article 2.17) is as follows:

- An invitation to tender is published in the Government Gazette and sent for publication in the Official Journal of the European Union. The deadline for the submission of the offers is defined in the invitation to tender and cannot be less than ninety (90) days from the day of the last publication.

- An interested party for an area that is not included in the invitation to tender can submit an application. The HHRM, if the application is accepted, then issues an invitation to tender, which is approved by the Minister of Energy, published in the Government Gazette and sent for publication in the Official Journal of the European Union. The deadline for the submission of offers by other interested parties is at least ninety (90) days from the day of the last publication.
- Interested parties may tender for a concession in one or more areas if those areas, following an open invitation to tender, are available on a permanent basis or have been the subject of a previous procedure which has not resulted in the signing of a lease agreement or a production sharing agreement or has been abandoned by the contractor, (withdrawn from the agreement or has terminated it) and the Minister of Energy, by notice, has published in the Government Gazette and sent for publication in the Official Journal of the European Union the above areas with the minimum basic terms of the concessions as well as any other relevant information. The offers are submitted until the last day of the first and second semester of each calendar year. Within thirty (30) days from the end of the semester, the Minister of Energy announces that the area is excluded from the areas which are available as above, in case the area is on an ongoing process of concession. The offers are evaluated and among them is selected the one most advantageous to the State, following negotiations with the interested parties and based on the selection criteria of the open invitation. The deadline for submission of offers is specified in the call for tenders and cannot be less than ninety (90) days from the day of last publication.

Presidential Decree 127/1996

In conjunction with the Hydrocarbons Law, Presidential Decree 127/1996, under the title "*Lease Terms of the Right for Exploration and Exploitation of Hydrocarbons*", regulates the terms and conditions of hydrocarbon lease agreements. It regulates annual task schedules, estimated budgets, waivers of rights, income and expenses, pricing of hydrocarbons, dispute resolution and the extension of terms. It also provides for the formation of a committee for the removal and usage of installations upon the termination of the concession for exploitation.

Recent Amendments

The most recent amendment to the Hydrocarbons Law was Law 4001/2011. Law 4001/2011 transposes into national legislation EU Directives concerning common rules for the internal market in electricity and common rules for the internal market in gas that oblige EU member states to further liberalise their electricity and natural gas markets.

This piece of legislation gives legal ground to the reforms in the Greek energy sector, mostly consisting of partial privatisation of state-controlled energy companies. Amongst its main provisions, the law enhances the role of the independent regulator regarding energy security, licensing, monitoring of the market and consumer protection. Law 4001/2011 replaces Law 468/1976, the law that formed the basis for the development of the Prinos field in the 1970s and 1980s and transposed Directive 94/22/EC into Greek Law.

Rights of foreign investors (non-EU nationals)

Non-EU nationals (whether natural or legal persons) may be granted hydrocarbons prospecting, exploration and exploitation rights as long as the principle of reciprocity with their country of origin applies. The Ministerial Council may refuse the granting or the transfer of such rights to any entity which is effectively controlled by a third country or third country nationals on the grounds of national security. Likewise, change of control of the concessionaire from EU to non-EU controlling countries or nationals (either directly or indirectly) is not allowed without the prior consent of the Ministerial Council at the risk of forfeiting the concession. Control is understood to mean a holding of at least thirty percent (30%) of the voting share capital of an enterprise or the right to appoint the management.

Farm-ins and farm-outs

Similarly, transfers of parts or entire concessions to third parties or affiliates (including transfers resulting in change of control) are subject to the prior consent of the HHRM and approval by the Minister provided that the transferee meets the tender participation criteria (including financial and technical capabilities, and prior experience) and provided that there are no grounds standing of national security for the refusal of this consent. For the specific purpose of determining whether a farm-out is to an affiliate, control is understood to mean a holding in excess of fifty percent (50%) of the share capital.

Labour mobility

Concessionaires may freely employ EU citizens in general and non-EU citizens for petroleum operations requiring special expertise. Visas, residence and work permits are relatively easy to obtain for them and their families, unless there are reasons pertaining to national security or public order.

2.3 Fiscal regulations

The Hydrocarbons Law imposes an income tax of 20% plus a regional tax of 5% upon the lessee or the contractor, as the case may be. The income tax provisions of the law also involve a complex system of revenue classification and expense allowances. The Hydrocarbons Law also includes certain exemptions from customs duties. Articles 8 and 9 of the Hydrocarbons Law establish a detailed taxation framework which controls the tax assessment process.

The Hydrocarbons Law does not include specific provisions for the payment of royalties however these are payable in relation to Prinos and South Kavala under the lease agreement ratified by Greek Law 2779/1999. Royalties are payable by Energean to the Greek State on its annual gross income generated by the sale of petroleum, prior to the deduction of any expenses, according to a progressive rate in proportion to the average daily production of petroleum, as the latter results based on the total annual production, according to the table below. 2016 was the first year in which the Group's production reached the threshold for royalties to become payable.

Average Daily Production	Total Royalties
Up to 2,500 barrels	0%
From 2,501 to 5,0 barrels	3%
From 5,001 to 10,000 barrels	6%
From 10,001 barrels and more	10%

Under the Ioannina and Katakolo lease agreements, royalties, payable in cash or in kind, are calculated by reference to the relevant R-factor (i.e. cumulative revenues / cumulative costs) and imposed quarterly at escalating rates ranging from 2% to 20%.

Fiscal terms applicable under the leases

In addition the Group's Greek leases, as ratified by the Hellenic Parliament, contain certain fiscal terms.

Under the terms of the Prinos, Ioannina and Katakolo leases, the income tax plus the regional tax exhausts the income tax obligations of each co-lessee and its shareholders, members or partners with respect to the profits resulting from its petroleum operations. Withholding taxes other than dividend withholding taxes apply according to general provisions. VAT applies according to general VAT provisions, with a current rate of 24%.

Under these leases, certain exemptions are granted on stamp duties and other indirect taxes applied on loans and credit agreements, interest, and the payments (cash calls) paid by each co-lessee to the operator, provided that the purpose of funds granted is exclusively the financing of petroleum operations.

Under the Prinos lease, any additional capital expenditure will be deducted by 100% from the annual gross income at the respective year. Under the Ioannina and Katakolo leases, annual depreciation is permitted at 40% of the value of the annually produced and saved hydrocarbons and byproducts.

Tax losses in respect of the Prinos field can be utilised to offset taxable profits up to the termination of the Company's duration. Under the Ioannina and Katakolo leases, losses incurred in respect of a particular exploitation area prior to the commencement of any exploitable production shall be carried forward without any restrictions for such period, but from the commencement of production in any exploitation area onwards, the general income tax provisions shall apply (which currently apply a limit of five years).

For licences falling within the provisions of Law 2289/1995, up to 50% of exploration expenses in one contract area may be included in the expenses of another contract area for which the lessee or each co-lessee holds an exploitation licence according to the provisions of Law 2289/1995 and has commenced the production of hydrocarbons.

In addition to the taxes and royalties outlines above, the Ioannina and Katakolo lease agreements provide for signature bonuses of €0.5 million and €0.25 million respectively and production bonuses payable at specified cumulative production thresholds set out in the table below:

Ioannina	Katakolo
€1.5 million at 10 million boe	€0.5 million at 1 million boe
€7.5 million at 50 million boe	€1.0 million at 2.5 million boe
€15 million at 100 million boe	€2.0 million at 5 million boe

The Ioannina and Katakolo leases also provide for surface fees of €10/km^2 annually during the first phase of the exploration stage, €15/km^2 annually during the second phase of the exploration stage, and, in the case of Katakolo, €20/km^2 annually during third phase of the exploration stage, increasing under both leases to €200/km^2 annually during the exploitation stage.

2.4 Environmental regulations

Under the Hydrocarbons Law, the Minister of Energy may, upon the recommendation of HHRM, impose regulations for the performance of operations and projects of any kind, storage tanks and pipelines, the carrying out of drilling operations and the plugging of wells. Such regulations aim to (i) encourage the adoption of safety measures; (ii) prevent pollution or contamination of the environment; (iii) protect flora and fauna, fishing, navigation, antiquities in general, historic sites of special natural beauty; and (iv) other activities within the exploitation areas. The Minister of Energy may impose a fine of up to €1.5 million for every violation of such requirements. Fines for violating regulations relating to sea pollution and damage to flora and fauna may also be imposed by local port authorities.

To ensure compliance with, among others, the provisions set out above the Minister of Energy may require from a lessee or contractor a deposit guarantee, the amount of which is to be determined by the Minister, upon the recommendation of the HHRM, or, alternatively, an insurance contract with an international firm against all environmental risks.

With regard specifically to offshore areas where oil and gas operations take place, Directive 2013/30/EU18 on the safety of offshore oil and gas operations has recently been transposed into Greek law, by virtue of Law 4409/2016 (Official Government Gazette 136/A/2016). Further to the Directive's relevant provisions, Law 4409/2016 puts in place a set of rules in order to prevent major accidents in the context of offshore petroleum operations, and to ensure an adequate response system in cases of emergency.

More specifically, as regards the prevention of major accidents related to offshore petroleum operations, Article 3 paragraph 4 of Law 4409/2016 provides that the operators must conduct their operations on the basis of a risk management system in such a way as to ensure that the residual risks of major accidents to individuals, the environment or offshore installations, remain at an acceptable level. The operators will remain fully liable for any acts or omissions of the contractors they may engage.

The environmental permitting procedure for the Epsilon project is defined by the Law 4014/2011. This process and the requirements for EIA are aligned with the EU EIA Directive, which has been transposed into Greek legislation. The EIA process includes an impact assessment (the applicant shall provide an EIA of the project to the Ministry of Environment and Energy (YPEN), Directorate of Environmental Permitting ("**DIPA**")); check for completeness (DIPA/YPEN will check the EIA for completeness and may request additional information, prior to distributing for consultation); statutory consultation (opinion/response from the central authorities or other competent ministries, regional authorities and various organizations); public consultation (the project is presented to the regional council during an open hearing where people can express their views); decision on approval of environmental conditions (DIPA/YPEN will consider the results of the consultation (statutory and public) and will issue its decision, co-signed by other competent ministries); and publication of decision (publication of the decision through the relative regional council).

3. Regulatory and legislative framework in Montenegro

3.1 Exploration and production regulations

The Law on Exploration and Production of Hydrocarbons and its enabling regulations govern all the activities in the upstream sector in Montenegro; however, environmental and other issues not specific for the upstream sector are governed by relevant regulations.

Production field size is limited to 150km^2, or 300km^2 in the event of production from several smaller deposits. Decommissioning funds or some type of financial liability for decommissioning are mandatory.

3.2 Fiscal Regulations

Tender Application Fee

The tender application fee is a mandatory non-refundable fee that is paid on the occasion of applying to tender for an award of a concession for the exploration and production of oil and gas. While the level of these fees are not proscribed in the relevant legislation, for the first concession round these were €35,000.

Fee for the Area Used for Exploration and the Production of Oil and Gas (Usage Fee)

The principle applied to charging and calculating the Usage Fee is progressive and de-stimulating, meaning the longer the area is used the higher the fee. This policy is to encourage companies to relinquish areas they do not use productively. Proposed fee amounts for areas of hydrocarbon production are €300 per km^2 for years 1 to 7 and €3000 for year 8 and beyond. The fee will be adjusted at least every two years in line with the consumer price index. It is paid once a year in advance for the following calendar year; including accrued interest for late payment.

Fees for Produced Oil and Gas (Royalty)

Royalties are calculated based on the quantity of oil and gas produced. The calculation of this fee is regulated by a special secondary legislative act which prescribes, but is not limited to, the following:

- manner of payment of the royalty in money or the resource itself;
- manner of calculating the quantity of the hydrocarbons for the purpose of calculating the royalty, oil and gas calculated separately, as well as the measurement method;
- manner of establishing the value of the hydrocarbons for the purpose of calculating the royalty, based on the prevailing market price; and
- royalty rates are progressive and are tied to the daily production quantity from the moment the extracted quantity exceeds a defined daily production threshold (as set forth in the table below) of oil or gas using a 30-day average. Such a provision is required to prevent uncontrolled exploitation, in other words, to ensure optimum exploitation of a deposit. Royalties may lead to a situation where significant quantities of resources remain permanently unused.

Proposed royalty rates for hydrocarbons production:

Production in Barrels	Royalty Rate for Liquid Hydrocarbons	Royalty rate for gas%[(1)]
Less than 10,000	5%	2%
10,000 to 20,000	7%	2%
20,000 to 30,000	10%	2%
More than 30,000	12%	2%

Notes:

(1) This proposed rate of gas is low since there is no developed gas infrastructure in Montenegro. This is why the introduction of an environmental pollution fee has been proposed.

Additional provisions relating to the calculation of the royalty fee are as follows:

- the manner of calculating the hydrocarbon value for the fee calculation: market value at predefined norm prices;
- delivered hydrocarbons will be defined based on quality, and the crude oil definition should also be included, which is determined by specific pressure and temperature;
- the fee is paid on a quarterly basis, within 15 days from the day of receipt of the calculation fee; and
- the fee is subject to the accrual of interest in cases of late payment.

The royalty is not subject to tender bidding but is defined by regulation.

Extra Tax on Profits from Upstream Oil and Gas (Extra Tax)

Montenegro imposes an additional tax on activities in the oil and gas industry. This will be applied such that the overall tax rate will not exceed 54%. The information regarding the taxation model for this additional tax needs to be defined at the moment of announcing the tender to ensure transparency.

Therefore, a special law and secondary legislative acts will regulate the introduction of the Extra Tax of 54% with definitions of the rules for establishing revenues and expenses for tax purposes. The costs that are recognised for tax purposes include, but are not limited to, the following: operating expenses, capital costs,

depreciation, transfer of losses from previous years, interest on financing, costs of the fund in case of deposit abandonment. Detailed and clear accounting rules on allowed costs for tax purposes will be defined in order to prevent companies from misusing the accrual of costs.

Corporate Profit Tax for Upstream Companies

The application of the general 9% corporate tax on profits that are not generated from upstream activities will require rules for the recognition of revenues and expenses for tax purposes. The same Law on taxation of upstream industry and secondary legislation would regulate taxation model for these activities.

PART 8
DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

1. Directors

The following table lists the names, positions and ages of the Directors as of the date of this Prospectus:

Name	Age	Position
Simon Heale	64	Non-Executive Chairman
Matthaios Rigas	50	CEO
Panagiotis Benos	38	CFO
Andrew Bartlett	60	Senior Independent Director
Efstathios Topouzoglou	61	Non-Executive Director
David Bonanno	35	Non-Executive Director
Robert Peck	58	Independent Non-Executive Director
Ohad Marani	62	Independent Non-Executive Director
Karen Simon	58	Independent Non-Executive Director

The management expertise and experience of each of the Directors is set out below. Further information on the Directors, including the companies of which each Director has been a director at any time in the past five years, is set out in paragraphs 6 and 7 of Part 16 "*Additional Information*". The business address of each of the Directors is 21 Gloucester Place, London W1U 8HR.

Simon Heale, Non-Executive Chairman

Mr Heale has significant business operations and management experience gained through a diverse range of industries. Mr Heale joined Energean as Chairman in July 2017. Mr Heale previously served as chairman of Kaz Minerals (previously known as Kazakhmys plc) (until December 2017) and currently serves as chairman of GMS and Marex Spectron. Prior to this, Mr Heale served as a non-executive director and chairman of Panmure Gordon & Co from 2010 to 2011, as a non-executive director of Carlton Commodities Capital Corporate Member Limited from 2011 to 2016, of Morgan Advanced Materials from 2005 to 2014, of PZ Cussons from 2008 to 2013 and of Coats plc from 2011 to 2014. Mr Heale has extensive experience in senior executive roles, including as chief executive of the London Metal Exchange from 2001 to 2006, as chief operating officer of Jardine Fleming Ltd from 1999 to 2001, and as deputy managing director at Cathay Pacific Airways from 1994 to 1997. Mr Heale is a chartered accountant who began his career at PwC. Mr Heale holds a degree in Philosophy, Politics and Economics from Oriel College, Oxford.

Matthaios (Mathios) Rigas, Chief Executive Officer

Mr Rigas has 20 years of investment banking and private equity experience and is a founding shareholder of the Group, serving as CEO of the Group since 2007. During the years 2001 to 2007 Mr Rigas set up, and was managing partner of, Capital Connect Venture Partners, a private equity fund in Greece with investments in innovative enterprises in IT, healthcare, waste management and food industries. From 1999 to 2001 Mr Rigas was in charge of Piraeus Bank's shipping division. Prior to that, from 1993 to 1999, he was vice president of shipping, energy & project finance at Chase Manhattan Bank in London where he arranged financing in excess of US$5 billion, mainly in the oil and gas sector. Mr Rigas was formerly the chairman of the board of Tyres Herco S.A., a tire recycling company and MAVIN S.A., a company recycling agricultural and brewery by-products in Greece. Mr Rigas holds a degree in Mining and Metallurgical Engineering from the National Technical University of Athens and an MSc / DIC degree in Petroleum Engineering from Imperial College London.

Panagiotis (Panos) Benos, Chief Financial Officer

Mr Benos has 15 years international experience in the oil and gas sector, both in banking and industry, with a long track record of upstream financing in emerging markets. Mr Benos joined the Group in 2011 from Standard Chartered Bank, where he was a director in the oil and gas team in London delivering a number of award winning project and acquisition finance deals in Africa, Asia and the Middle East. Before that he worked for ConocoPhillips from 2002 to 2006, where he held positions in European treasury, North Sea economics and international downstream with a focus on the North Sea, Central Europe and the Middle East. He commenced his career at Royal Bank of Scotland in shipping finance. He is also a Chartered Accountant (ICAS) and holds an MSc in Shipping, Trade and Finance from Cass Business School.

Andrew Bartlett, Senior Independent Director

Mr Bartlett has over 30 years' experience in the upstream oil and gas industry and currently serves as a non-executive director for Africa Oil Corporation and Impact Oil & Gas and adviser to Helios Investment Partners LLP (a private equity partnership focused on Africa). Before his current directorships, Mr Bartlett served as the chairman and non-executive director of Azonto Energy from 2013 to 2015. He was also previously the global head of Oil & Gas M&A and Project Finance for Standard Chartered Bank between 2004 and 2011. Prior to this, he worked on the trading and derivatives desk of Standard Bank in South Africa. Before joining the investment banking industry, Mr Bartlett worked for Royal Dutch Shell between 1981 and 2001, as a petroleum engineer and development manager, where he gained extensive experience in the operation of oil and gas fields.

Efstathios Topouzoglou, Non-Executive Director

Mr Topouzoglou, is a founding shareholder of the Group and co-founder of Prime Marine Corporation ("**Prime**"), serving as Prime's chief executive officer and managing director. Prime, a leading worldwide product tanker company, is a major global provider of seaborne transportation for refined petroleum products, LPG and ammonia. Mr Topouzoglou has more than 35 years of experience in founding and growing companies in the energy transportation sector and holds a B.A. in Business Administration and Economics from the University of Athens, Greece.

David Bonanno, Non-Executive Director

Mr Bonanno joined Third Point, the Company's principal shareholder, in 2008. Mr Bonanno is a managing director at Third Point and his focus is on special situation opportunities in the US and Europe. Mr Bonanno acts as the primary investment professional responsible for all Third Point's Hellenic Recovery Fund L.P. activities in Greece. Prior to joining Third Point, Mr Bonanno was an associate in the private equity and distressed investments group at Cerberus Capital Management, L.P from 2006 to 2008. Prior to this, he was an analyst in the restructuring and reorganization advisory group at Rothschild Inc. from 2004 to 2006. Mr Bonanno graduated *cum laude* from Harvard University with a B.A. in Psychology.

Robert Peck, Independent Non-Executive Director

Ambassador Peck worked for 35 years in the Government of Canada as a career Foreign Service Officer. Ambassador Peck was formerly Senior Advisor in the Human Resources Bureau, a department of the Government of Canada, where he served as resident mentor to nearly thirty first-time Heads of Mission. Ambassador Peck was Canada's Ambassador to the People's Democratic Republic of Algeria from 2004 to 2007 and Ambassador to Greece and High Commissioner to the Republic of Cyprus from 2011 to 2015. Ambassador Peck was also Counsellor to the Canadian Embassy in Greece from 1995 to 1998. As Canada's representative to both Algeria and Greece, Ambassador Peck worked closely with the Canadian oil and gas and mining sectors. During a two-year leave of absence from the Government of Canada, Ambassador Peck was Director of Corporate Communications and Investor Relations at CAE Inc., the global leader in aerospace simulation technology. In addition, Ambassador Peck was Chief of Protocol of Canada in the Foreign Affairs and International Trade Department. Ambassador Peck holds a B.A. in History and Journalism from Concordia University in Montréal.

Ohad Marani, Independent Non-Executive Director

Mr Marani has significant experience in the Israeli finance and energy sectors, and in the Israeli government as well. Mr Marani has been a board member of Bank Leumi of Israel Ltd since October 2015 and also a member of the Investment Committee of Israel's Infrastructure Fund since 2006. Mr Marani held several managerial positions in the energy sector, including the following positions: Chief Executive Officer of the Israel Land Development Company Energy Ltd from April 2010 to September 2015, the position of Chairman of the board of Emmanuelle Energy from 2010 to 2015, and Chairman of the board of Israel Natural Gas Lines Ltd from 2008 to 2010. Mr Marani was also the Executive Chairman of the board of ORL Ltd- the Israeli Oil Refineries and Petrochemical Company from 2004 to 2007 and led this company to a very successful IPO. Mr. Marani served in senior positions in the Israeli government, including the following positions: Director-General of the Israeli Finance Ministry from 2001 to 2003, Director General of the Budget Department of the State of Israel from 2000 to 2001 and Minister of Economic Affairs at the Israeli Embassy in Washington from 1995 to 2000. Mr Marani holds an MA in Public Administration with a major in Economics and Finance from Harvard University, an MBA with major in Finance from the Hebrew University of Jerusalem and a BA in Economics with a major in Accounting and Statistics from the Hebrew University of Jerusalem

Karen Simon, Independent Non-Executive Director

Ms Simon has been with J.P.Morgan for over 34 year and is a Vice Chairman in the Investment Bank. Her career includes senior roles in Oil & Gas, Debt Capital Markets and Private Equity coverage. Ms Simon was the Head

of Financial Sponsor Coverage for J.P. Morgan in both New York and in London from 2007 to 2016, serving further as Global co-head including Asia. Previous to this, Ms. Simon was co-head of Debt Capital Markets for EMEA and spent the first 15 years of her career in various positions in the Oil & Gas division in Houston and London. She sits on the boards of directors for Aker ASA in Oslo, Norway and the non-profit Dallas Women's Foundation. Ms. Simon resides in Dallas, Texas.

2. Senior managers

The current senior management team of the Group is as follows:

Name	Age	Position
Mathios Rigas	50	CEO
Panos Benos	38	CFO
Dr Stephen Moore	55	Group Technical Director and Karish & Tanin Project Director
James Efstathiou	59	Exploration Director
David Donaldson	60	Prinos Asset Manager and Managing Director, Kavala Oil S.A.
Fred Riddiford	62	Reservoir Engineering Manager

The management expertise and experience of each of the Senior Managers is set out below. Further information on the Senior Managers, including the companies of which each Senior Manager has been a director at any time in the past five years, is set out in paragraphs 6 and 7 of Part 16 "*Additional Information*". The business address of each of the Senior Managers is Energean Oil & Gas plc, 21 Gloucester Place, London W1U 8HR, United Kingdom.

Mathios Rigas, Chief Executive Officer

Mr Rigas is the Chief Executive Officer of the Group. For biographical information, please see "*—Directors—Mathios Rigas, Chief Executive Officer*" above.

Panos Benos, Chief Financial Officer

Mr Benos is the Chief Financial Officer of the Group. For biographical information, please see "*—Directors—Panagiotis Benos, Chief Financial Officer*" above.

Dr Stephen Moore, Group Technical Director and Karish & Tanin Project Director

Dr Moore is an E&P technical professional with 31 years of experience at Shell, Maersk, Oil and Mubadala Petroleum. He joined the Group in 2014, having previously held the position of Senior Vice President- Technical at Mubadala Petroleum. During the first half of his career, Dr Moore worked in a variety of operational and process engineering roles. Dr Moore has worked extensively in the Former Soviet Union, in the Middle East, South East Asia as well as the UK sector of the North Sea. Dr Moore holds a BSc in Chemical Engineering (1st class hons) from the University of Newcastle upon Tyne, UK and a Ph.D. in Chemical Engineering from the same university.

James Efstathiou, Exploration Director

Mr Efstathiou is an exploration manager and geoscientist with 37 years of oil industry experience, having previously worked as Global Exploration Manager (from 2014 to 2016) and Exploration Manager (from 2012-2014) at Mubadala Petroleum, where he was responsible for all captured assets and Exploration New Ventures. Prior to Mubadala, Mr Efstathiou was the Middle East exploration and development New Ventures manager for Statoil in the UAE from 2008 to 2012. Previous roles include Middle East exploration manager at StatoilHydro from 2007 to 2008 and Chief/Senior Geophysicist for offshore West Africa at Norsk Hydro from 1993 to 2007. Mr Efstathiou previously worked with BP and GSI (seconded to Saudi Aramco) in London. Mr Efstathiou holds a BSc (Hons) in Geophysical Science from Southampton University.

David Donaldson, Prinos Asset Manager and Managing Director, Kavala Oil S.A.

Mr Donaldson is a petroleum engineer with drilling specialization and over 30 years of industry experience. Mr Donaldson previously served as Well Engineering Manager at Petroceltic, Algeria, where he was responsible

for the drilling of 124 land wells, including the planning, programming, recruitment and delivery of 30 early wells and field infrastructure of tight gas, as well as HSE management, risk analysis, QA/QC management and cost management. Previously, Mr Donaldson served as drilling engineer in senior positions for BG Group (including Vice President and Well Engineering Manager), Shell (Asset Divestment), Eni (Petroleum Engineering Coordinator), Petro-Canada (Snr Petroleum Engineer), BHP Billiton (Well Services Superintendent) and Halliburton (Senior Advisor Snubbing and HWO, Coiled Tubing Manager). Mr. Donaldson holds a master's degree in Petroleum Engineering from Heriot-Watt University.

Fred Riddiford, Reservoir Engineering Manager

Mr Riddiford is a reservoir engineering and project engineering technical professional and senior manager who has worked on oil and gas-related projects for the past 40 years. He joined Energean in June 2016. Mr Riddiford previously worked in the Petro-Technical Group in Mubadala Petroleum as Vice President Reservoir Engineering from 2013 to 2016 and Director Reservoir Engineering from 2011 to 2013 in Abu Dhabi. He began a 35-year career at BP as a Research Physicist before transferring to the E&P arm of the company in 1984 as a Reservoir Engineer. More recently, Mr Riddiford developed the In Salah Gas (ISG) Field during the period from 1996 to 2004 as Team Lead and then Senior Reservoir Engineer and won a BP Helios Green Prize Award in 2005 for the ISG CO2 Re-injection Project, before taking his final position at BP as Technical Manager of the Growth/ Technical Directorate (Middle East & South Asia SPU, from 2004 to 2010).

3. Corporate governance

3.1 UK Corporate Governance Code

The Board is committed to the highest standards of corporate governance. As of the date of this Prospectus and on and following Admission, the Board will comply with the UK Corporate Governance Code (the "**Governance Code**") published in April 2016 by the Financial Reporting Council.

The Board comprises an independent non-executive chairman, two Executive Directors and six Non-Executive Directors. The Company regards all of the Non-Executive Directors to be independent within the meaning of "independent" as defined in the Governance Code, other than David Bonanno and Efstathios Topouzoglou. While each of Mr Bonanno and Mr Topouzoglou are considered to be independent in character and judgement, David Bonanno is not deemed to be "independent" as a result of representing Third Point, which is expected to hold approximately 27% of the Shares of the Company on Admission, while Efstathiou Topouzoglou is not deemed to be "independent" as a result of representing Oilco Investments, which is expected to hold approximately 12% of the Shares of the Company on Admission.

The Board plans to meet on at least six occasions during the course of the year to review trading performance and budgets, funding, to set and monitor strategy, examine acquisition opportunities and report to shareholders. The Board may also meet at other times at the request of one or more of the Directors. The Board has a formal schedule of matters specifically reserved to it for decisions. The roles of Chairman and Chief Executive Officer are separate and the responsibilities of Chairman and Chief Executive Officer are independently defined. It is the Chairman's responsibility to provide leadership of the Board and set the overall objectives and strategic direction of the Company as well as to ensure that the Board is provided with accurate, timely and clear information in relation to the Group and its business. The Chief Executive Officer will have day-to-day executive responsibility for the running of the Company's businesses. The Chairman and Chief Executive Officer will share responsibility for the representation of the Company to third parties.

The Governance Code recommends that the Board should appoint one of its Independent Non-Executive Directors to be the Senior Independent Director. The Senior Independent Director should be available to shareholders if they have concerns that contact through the normal channels of Chairman, Chief Executive Officer or Chief Financial Officer has failed to resolve or where such contact is inappropriate. Andrew Bartlett is the Board's senior independent director and will continue in this role following Admission.

3.2 Board committees

The Board has appointed an audit and risk committee, a remuneration committee, a nomination and governance committee and a health, safety and environment committee. The members of these committees are appointed principally from among the independent directors and all appointments to these committees shall be for an initial period of up to three years and may be extended by no more than two additional three year periods. The terms of reference of the committees have been drawn up in accordance with the provisions of the Governance Code. A summary of the terms of reference of each of these committees is set out below.

Audit and risk committee

The audit and risk committee's role is to assist the Board with the discharge of its responsibilities in relation to financial reporting, including reviewing the Group's annual and half year financial statements and accounting policies, internal and external audits and controls, reviewing and monitoring the scope of the annual audit and the extent of the non-audit work undertaken by external auditors, advising on the appointment of external auditors and reviewing the effectiveness of the internal audit, internal controls, whistleblowing and fraud systems in place within the Group. The audit and risk committee shall additionally oversee and advise the Board on the Group's overall risk appetite, tolerance and strategy, review the Company's capability to identify and manage new types of risk and keep under review the Group's overall risk assessment processes that inform the Board's decision making. The audit and risk committee will meet at such times as are necessary, but not less than four times a year. The audit and risk committee will consider annually how the Group's internal audit requirements shall be satisfied and makes recommendations to the Board accordingly as well as on any area it deems needs improvement or action.

The audit and risk committee is chaired by Andrew Bartlett and its other members are Ohad Marani and Robert Peck. It is the opinion of the Directors that Andrew Bartlett has recent and relevant financial experience and is appropriate to chair the audit and risk committee. The Governance Code recommends that the audit and risk committee should consist of at least three independent non-executive directors and that at least one such member has recent and relevant financial experience. The Board considers that the Company complies with the requirements of the Governance Code in this respect.

Nomination and governance committee

The nomination and governance committee assists the Board in reviewing the structure, size and composition of the Board, including providing advice to the Board on the retirement and appointment of additional and/or replacement Directors. It is also responsible for reviewing succession plans for the Directors, including the Chairman and Chief Executive and other senior executives. The nomination and governance committee will meet at such times as are necessary, but not less than twice a year.

The nomination and governance committee is chaired by Simon Heale and its other members are Andrew Bartlett and Efstathios Topouzoglou. The Governance Code recommends that a majority of the members of the nomination and governance committee be independent non-executive directors and that the Chairman (other than where the committee is dealing with the appointment of a successor to the chairmanship) or an independent non-executive director should chair the committee. The Board considers that the Company complies with the requirements of the Governance Code in this respect.

Remuneration committee

The remuneration committee recommends the Group's policy and framework on executive remuneration, determines the levels of remuneration for Executive Directors, the Chairman and other senior executives and prepares an annual remuneration report for approval by the Shareholders at the annual general meeting. The remuneration committee will also review the scale and structure of Executive Directors' remuneration and the terms of their service or employment contracts, including share based schemes, other employee incentive schemes adopted by the Company from time to time and pension contributions and ensure that payments made on termination are fair to the individual and the Company. The remuneration committee will meet at such times as are necessary, but not less than twice a year.

The remuneration committee is chaired by Ohad Marani, and its other members are Andrew Bartlett, David Bonanno and Robert Peck. The Governance Code recommends that the remuneration committee should consist of at least three independent non-executive directors. The Board considers that the Group complies with the requirements of the Governance Code in this respect.

Health, safety and environment committee

The health, safety and environment committee evaluates the effectiveness of the Group's policies and systems for identifying and managing environmental, health and safety risks within the Group's operations. Additionally, the health, safety and environment committee assesses the performance of the group with regard to the impact of environmental, health and safety decisions and actions upon employees, communities and other third parties. The health, safety and environment committee will meet at such times as are necessary, but not less than twice a year.

The health, safety and environment committee is chaired by Robert Peck, and its other members are Karen Simon and Ohad Marani.

3.3 Share dealing code

The Company has adopted, with effect from Admission, a code of securities dealings in relation to the Shares which is based on the requirements of Regulation (EU) 596/2014 (the "**Market Abuse Regulation**"). The code adopted will apply to the Directors and other relevant employees of the Group.

3.4 Other

Each committee and each Director has the authority to seek independent professional advice where necessary to discharge their respective duties, in each case at the Company's expense. In addition, each Director and committee has access to the advice of the Company Secretary, Michelle Churchward.

The Company has also implemented internal procedures and measures designed to ensure compliance by it and other members of the Group with the Bribery Act.

4. Conflicts of interest

There are no potential conflicts of interest between any duties owed by the Directors or Senior Managers to the Company and their private interests or other duties.

PART 9
PRINCIPAL SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

1. Principal Shareholders

As at the Latest Practicable Date and as expected immediately following Admission, in so far as is known to the Company, the following persons held or are expected to hold an interest which represents 3% or more of the voting rights attached to the issued share capital of the Company, and the amount of such person's interest, is as follows:

	As at the Latest Practicable Date		Immediately following Admission	
Shareholder	**Number of Shares**	**Percentage of issued share capital**	**Number of Shares**	**Percentage of issued share capital**
Third Point Hellenic Recovery (Lux) S.À R.L.	40,782,418	51.1%	40,782,418	26.7%
Growthy Holdings Co. Limited[(1)]	18,688,224	23.4%	19,437,816	12.7%
Oilco Investments Limited[(2)]	16,281,257	20.4%	17,819,893	11.7%
Adobelero Holdings Co. Ltd[(3)]	3,976,809	5.0%	4,055,713	2.7%
Clal Insurance	—	—	15,780,878	10.3%
Capital Research Global Investors	—	—	10,874,957	7.1%
Pelham Capital	—	—	7,251,942	4.7%
Kerogen	—	—	5,523,308	3.6%

Notes:

(1) Number of shares shown represents the aggregate shareholding of Mathios Rigas as an individual and his indirect holdings by virtue of his controlling interest in Growthy Holdings Co. Limited and Capital Energy Investments Limited.

(2) Number of shares shown represents the aggregate shareholding of Efstathios Topouzoglou as an individual and his indirect holdings by virtue of his controlling interest in Oilco Investments Limited and HIL Hydrocarbon Investments Limited.

(3) Number of shares shown represents the shareholding of Panos Benos by virtue of his controlling interest in Adobelero Holdings Co. Ltd.

None of the Shareholders detailed above have voting rights which differ in any way from those of the Company's other Shareholders. So far as the Company is aware, save as set out in the table above, no person has an interest which represents 3% or more of the issued share capital or voting rights of the Company, which would be notifiable under the Disclosure Guidance and Transparency Rules following Admission.

So far as the Company is aware, as of the Latest Practicable Date, there are no arrangements the operation of which may at a later date result in a change of control of the Company.

The Company is not aware of any person who either as of the date of this Prospectus or immediately following Admission exercises, or could exercise, directly or indirectly, control over the Company.

Each of Third Point, Growthy Holdings and Oilco Investments will be a substantial shareholder of, a "person exercising significant influence" over, and a "related party" to, the Company for the purposes of the Listing Rules.

2. Relationship Agreements

2.1 Relationship Agreement with Third Point

On Admission, Third Point is expected to own approximately 27% of the issued share capital of the Company.

On 16 March 2018, the Company entered into a relationship agreement with Third Point (the "**Third Point Relationship Agreement**") which will, conditional upon Admission, regulate (in part) the degree of control that Third Point and its associates may exercise over the management of the Company. The principal purposes of the Third Point Relationship Agreement are to ensure that the Company is capable at all times of carrying on its business independently of Third Point and its associates and that all of the Company's transactions and relationships with Third Point and its associates are at arm's length and on normal commercial terms.

The Third Point Relationship Agreement will continue until the earlier of (i) the Shares ceasing to be admitted to the premium listing segment of the Official List of the FCA and to trading on the London Stock Exchange or (ii) Third Point (together with its associates) ceasing to be entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings.

Under the Third Point Relationship Agreement, Third Point undertakes that:

(a) it will, and will procure its associates will, allow the Company and each company in the Group at all times to carry on its business independently of Third Point and its associates;

(b) it will not, and will procure its associates will not, act in any way which shall prejudice the ability of the Company and each company in the Group to carry on its business independently of Third Point and its associates;

(c) for so long as Third Point (together with its associates) is entitled to exercise, or control the exercise of, 15% or more of the rights to vote at the Company's general meeting, it will not, and will procure its associates will not, take any action (or omit to take any action) to prejudice the Company's status as a listed company or its suitability for listing under the Listing Rules after Admission has occurred or the Company's ongoing compliance with the Listing Rules and the Disclosure Guidance and Transparency Rules or have the effect of preventing the Company from complying with its obligations under the Listing Rules, provided that this shall not prevent Third Point (or any other person) from:

  (i) accepting a takeover offer for the Company made in accordance with the City Code (a "**Takeover Offer**") in relation to their respective interests in the Company or, where such Takeover Offer is made by way of a scheme of arrangement under Part 26 of the Act (a "**CA2006 Scheme**"), voting in favour of such CA2006 Scheme at the court and related shareholder meetings or otherwise agreeing to sell their Shares in connection with a Takeover Offer; or

  (ii) making a Takeover Offer by way of a general offer for all the outstanding Shares or by way of a CA2006 Scheme and de-listing the Company after such Takeover Offer has become wholly unconditional or, in the case of a CA2006 Scheme, after it has become effective;

  (iii) giving an irrevocable undertaking to a third party in connection with a Takeover Offer or a Scheme;

  (iv) purchasing shares in the market in connection with a Takeover Offer; or

  (v) taking any action in circumstances where it considers in good faith that the Company is acting illegally or in respect of any alleged fraud by the Company;

(d) it will abstain from voting on any resolution required by paragraph 11.1.7R(3) of the Listing Rules to approve a transaction involving Third Point or any of its associates; and

(e) it will exercise its voting rights in such a manner as to procure (to the extent possible):

  (i) at least half of the Board comprises independent directors (excluding the chairman of the Board), unless otherwise agreed by the independent directors;

  (ii) the Audit and Risk Committee and the Remuneration Committee shall comprise at least three independent directors who comprise at all times a majority of the members of such committee; and

  (iii) the Nomination and Governance Committee and any other committee of the Board to which significant powers, authorities or discretions are delegated shall at all times consist of a majority of independent directors.

Both Third Point and the Company undertake that they shall, with effect from the date of the Third Point Relationship Agreement, conduct any transactions and relationships (whether contractual or otherwise, including any subsequent amendment thereof or variation thereto, including the implementation or enforcement thereof) between Third Point or any of its associates, on the one hand, and of the Company or any of its associates, on the other, on arm's length terms and on normal commercial terms, and, where applicable, will be entered into in accordance with the related party transaction rules set out in Chapter 11 of the Listing Rules. Third Point further undertakes to procure that each of its associates will comply with the terms set out in this paragraph.

The Company undertakes that it shall treat all holders of the same class of Shares that are in the same position equally in respect of the rights attaching to such shares, save that the Company has agreed that Third Point shall have the right to nominate one director to the Board so long as Third Point (and/or its

associates) own 10% or more of the issued Shares (such person being a "**Third Point Director**"). It is also acknowledged that each of Growthy Holdings and Oilco shall also have the right to nominate one director to the Board so long as such shareholder (and/or its associates) owns 10% or more of the issued Shares.

Nothing in the Third Point Relationship Agreement shall prevent the Third Point Director from performing any duty or exercising any discretion in such manner as the Third Point Director sees fit in his capacity as a director of the Company or any company in the Group.

The Directors believe that the terms of the Third Point Relationship Agreement will enable the Company to carry on its business independently from Third Point and its associates, and ensure that (subject to other existing contractual arrangements with Third Point as of the date of Admission) all transactions and relationships between the Company and Third Point and its associates are, and will be, at arm's length and on a normal commercial basis, such that Third Point is not able to abuse its position as a major shareholder of the Company.

2.2 Relationship Agreement with Growthy Holdings

On Admission, Growthy Holdings is expected to own approximately 13% of the issued share capital of the Company.

On 16 March 2018, the Company entered into a relationship agreement with Growthy Holdings (the "**Growthy Holdings Relationship Agreement**") which will, conditional upon Admission, regulate (in part) the degree of control that Growthy Holdings and its associates may exercise over the management of the Company. The principal purposes of the Growthy Holdings Relationship Agreement are to ensure that the Company is capable at all times of carrying on its business independently of Growthy Holdings and its associates and that all of the Company's transactions and relationships with Growthy Holdings and its associates are at arm's length and on normal commercial terms.

The Growthy Holdings Relationship Agreement will continue until the earlier of (i) the Shares ceasing to be admitted to the premium listing segment of the Official List of the FCA and to trading on the London Stock Exchange or (ii) Growthy Holdings (together with its associates) ceasing to be entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings.

Under the Growthy Holdings Relationship Agreement, Growthy Holdings undertakes that:

(a) it will, and will procure its associates will, allow the Company and each company in the Group at all times to carry on its business independently of Growthy Holdings and its associates;

(b) it will not, and will procure its associates will not, act in any way which shall prejudice the ability of the Company and each company in the Group to carry on its business independently of Growthy Holdings or its associates; and

(c) it will abstain from voting on any resolution required by paragraph 11.7.7R(3) of the Listing Rules to approve a transaction involving Growthy Holdings or any of its associates.

Both Growthy Holdings and the Company undertake that they shall (and shall procure that the relevant members of their respective associates shall) with effect from the date of the Growthy Holdings Relationship Agreement conduct any transactions and relationships (whether contractual or otherwise, including any subsequent amendment thereof or variation thereto, including the implementation or enforcement thereof) between Growthy Holdings or any of its associates, on the one hand, and of the Company or any of its associates, on the other, on arm's length terms and on a normal commercial basis.

The Company undertakes that it shall treat all holders of the same class of Shares that are in the same position equally in respect of the rights attaching to such shares, save that the Company has agreed that Growthy Holdings shall have the right to nominate one director to the Board so long as Growthy Holdings (and its associates) own 10% or more of the issued Shares (such person being a "**Growthy Holdings Director**"). It is also acknowledged that each of Third Point and Oilco shall also have the right to nominate one director to the Board so long as such shareholder (and/or its associates) owns 10% or more of the issued Shares.

Nothing in the Growthy Holdings Relationship Agreement shall prevent the Growthy Holdings Director from performing any duty or exercising any discretion in such manner as the Growthy Holdings Director sees fit in his capacity as a director of the Company or any company in the Group.

The Directors believe that the terms of the Growthy Holdings Relationship Agreement will enable the Company to carry on its business independently from Growthy Holdings and its associates, and ensure that

(subject to other existing contractual arrangements with Growthy Holdings as of the date of Admission) all transactions and relationships between the Company and Growthy Holdings and its associates are, and will be, at arm's length and on a normal commercial basis.

2.3 Relationship Agreement with Oilco Investments

On Admission, Oilco Investments is expected to own approximately 12% of the issued share capital of the Company.

On 16 March 2018, the Company entered into a relationship agreement with Oilco Investments (the "**Oilco Investments Relationship Agreement**") which will, conditional upon Admission, regulate (in part) the degree of control that Oilco Investments and its associates may exercise over the management of the Company. The principal purposes of the Oilco Investments Relationship Agreement are to ensure that the Company is capable at all times of carrying on its business independently of Oilco Investments and its associates and that all of the Company's transactions and relationships with Oilco Investments and its associates are at arm's length and on normal commercial terms.

The Oilco Investments Relationship Agreement will continue until the earlier of (i) the Shares ceasing to be admitted to the premium listing segment of the Official List of the FCA and to trading on the London Stock Exchange or (ii) Oilco Investments (together with its associates) ceasing to be entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings.

Under the Oilco Investments Relationship Agreement, Oilco Investments undertakes that:

(a) it will, and will procure its associates will, allow the Company and each company in the Group at all times to carry on its business independently of Oilco Investments and its associates;

(b) it will not, and will procure its associates will not, act in any way which shall prejudice the ability of the Company and each company in the Group to carry on its business independently of Oilco Investments or its associates; and

(c) it will abstain from voting on any resolution required by paragraph 11.7.7R(3) of the Listing Rules to approve a transaction involving Oilco Investments or any of its associates.

Both Oilco Investments and the Company undertake that they shall (and shall procure that the relevant members of their respective associates shall) with effect from the date of the Oilco Investments Relationship Agreement conduct any transactions and relationships (whether contractual or otherwise, including any subsequent amendment thereof or variation thereto, including the implementation or enforcement thereof) between Oilco Investments or any of its associates, on the one hand, and of the Company or any of its associates, on the other, on arm's length terms and on a normal commercial basis.

The Company undertakes that it shall treat all holders of the same class of Shares that are in the same position equally in respect of the rights attaching to such shares, save that the Company has agreed that Oilco Investments shall have the right to nominate one director to the Board so long as Oilco Investments (and its associates) own 10% or more of the issued Shares (such person being an "**Oilco Investments Director**"). It is also acknowledged that each of Growthy Holdings and Third Point shall also have the right to nominate one director to the Board so long as such shareholder (and/or its associates) owns 10% or more of the issued Shares.

Nothing in the Oilco Investments Relationship Agreement shall prevent the Oilco Investments Director from performing any duty or exercising any discretion in such manner as the Oilco Investments Director sees fit in his capacity as a director of the Company or any of its affiliates.

The Directors believe that the terms of the Oilco Investments Relationship Agreement will enable the Company to carry on its business independently from Oilco Investments and its associates, and ensure that (subject to other existing contractual arrangements with Oilco Investments as of the date of Admission) all transactions and relationships between the Company and Oilco Investments and its associates are, and will be, at arm's length and on a normal commercial basis.

3. Related party transactions

The following is a description of the material transactions with related parties to which the Company or its subsidiaries are a party. The Company believes that it has executed all of its transactions with related parties on terms no less favourable to the Group than those it could have obtained from unaffiliated third parties.

Save as disclosed below and in note 33 of Section B of Part 13 "*Consolidated Historical Financial Information*", there were no related party transactions entered into during the period covered by the Consolidated Historical Financial Information in this Prospectus and up to the date of this Prospectus.

3.1 Reorganisation in connection with Admission

On 30 June 2017, the Company entered into a reorganisation agreement relating to the restructuring of the Group in preparation for Admission (the "**Reorganisation**") with the existing shareholders of Energean E&P Holdings (the "**Existing Shareholders**"), Energean E&P Holdings, Energean Israel and Energean International (the "**Reorganisation Agreement**"). Pursuant to the terms of the Reorganisation Agreement, the Company agreed to acquire the entire issued share capital of Energean E&P Holdings from the Existing Shareholders in consideration for the issue of 65,643,120 new Shares (representing 92.9% of the issued share capital of the Company as at 30 June 2017). As at the date of this document, the Company holds a direct interest in 99.7% of the issued share capital of Energean E&P Holdings, with the remaining 0.3% (which is owned by Capital Energy Investments Ltd, a company controlled by Mathios Rigas, and HIL Hydrocarbon Investments Ltd, a company controlled by Efstathios Topouzoglou) being held on trust for the Company. The Company will acquire the remaining 0.3% of the share capital of Energean E&P Holdings on the same terms as applied under the Reorganisation Agreement once Capital Energy Investments Ltd and HIL Hydrocarbon Investments Ltd are able to discharge certain security over their shares in Energean E&P Holdings which process is ongoing. As a result of the Reorganisation and the entry into the Reorganisation Agreement, the Company became the holding company of the Group on 30 June 2017.

The Reorganisation Agreement also contained provisions for (i) the repayment on 30 June 2017 of a US$227.7 million shareholder loan from Third Point, Growthy Holdings and Oilco Investments to Energean International by the issue on 30 June 2017 of certain preference shares in Energean International (the "**EIL Preference Shares**") to Third Point, Growthy Holdings and Oilco Investments, (ii) the acquisition on the business day prior to the date of this prospectus of the EIL Preference Shares by the Company in consideration for the issue of new Shares to Third Point, Growthy Holdings and Oilco Investments pro rata to their holdings of EIL Preference Shares (the "**Acquisition Shares**") and (iii) the repayment of shareholder funding made by Growthy Holdings, Oilco Investments and Adobelero to Energean Israel (in the form of class B shares issued by Energean Israel (the "**EISL Class B Shares**")), to be implemented by the acquisition on the business day prior to the date of this prospectus of the EISL Class B Shares by the Company in consideration for the issue of new Shares to Growthy Holdings, Oilco Investments and Adobelero.

Additionally, pursuant to the Reorganisation Agreement, the Existing Shareholders terminated their previous shareholders agreement relating to Energean E&P Holdings with effect from 30 June 2017 and entered into a separate shareholders agreement (on substantially similar terms) in respect of the Company (the "**New Shareholders Agreement**").

Pursuant to the New Shareholders Agreement, the Existing Shareholders agreed certain corporate governance issues in relation to the Company and the process to Admission. The New Shareholders Agreement will terminate on and with effect from the date of Admission in accordance with its terms.

On 31 October 2017, the Company entered into a supplementary agreement to the Reorganisation Agreement with the parties to the Reorganisation Agreement (the "**Supplementary Agreement**") which amended in part the terms of the Reorganisation. Pursuant to the terms of the Supplementary Agreement, (i) the Company agreed to acquire the EISL Class B Shares from Growthy Holdings, Oilco Investments and Adobelero for US$10 million in cash (rather than for the issue of Shares as contemplated by the Reorganisation Agreement), (ii) Growthy Holdings and Oilco Investments agreed to transfer all of their EIL Preference Shares to Third Point on the business day prior to the date of this document and (iii) the Company and Third Point (in anticipation of being the sole holder of the EIL Preference Shares) agreed to make a consequential adjustment to the calculation of the number of Acquisition Shares to be issued in connection with the acquisition of the EIL Preference Shares by the Company. The terms of the Supplementary Agreement did not affect the relative economic interests of the Major Shareholders in the Company as at the date of the Reorganisation Agreement, but reduced the number of Acquisition Shares to be issued by the Company as compared to the terms of the Reorganisation Agreement.

3.2 Related Party Transactions with Directors

Directors' Remuneration

The Directors are remunerated for their services on the basis set out in paragraph 7 of Part 16 "*Additional Information*".

Seven Marine

The offshore supply ship "Valiant Energy" supports Energean's ongoing investment programme in the Gulf of Kavala. In May 2016, the Group sold the Valiant Energy to Seven Marine, a company controlled by Efstathios Topouzoglou and in which Panos Benos holds a 19.6% interest, in a sale and leaseback arrangement. Seven Marine also owns the supply vessel "Energean Wave" which the Group charters to transport personnel to its offshore facilities in the Gulf of Kavala.

The Valiant Energy and the Energean Wave are separately leased under a two-year fixed term time charter at an annual cost of US$4 million and US$2.4 million respectively. Under the time-charter arrangements, Seven Marine incurs all costs relating to wages, fuel, crew and insurance related to the vessels.

See also paragraph 10.3 of Part 5 "*Business Overview—Infrastructure—Supply Vessels*".

3.3 Shareholder loans

Historically, the Group was financed primarily through investment in share capital and loans from previous and existing shareholders and their related entities. The following table shows the amount of such loans outstanding as of the dates presented:

	2016	2015	2014
		US$000	
At 1 January	186,181	116,568	–
Loans received during the year	10,000	54,653	125,000
Loans converted into ordinary shares during the year	–	–	–
Loans repaid	–	–	–
Accrued interest, net of discount	28,706	14,960	(8,432)
At 31 December	**224,887**	**186,181**	**116,568**

	2017
	US$ 000
At 1 January	224,887
Loans received during the year	–
Loans converted into preference shares in Energean International Limited (subsidiary)	(224,000)
Loans converted into shares in Energean Israel Limited (deconsolidated at 13 June 2017)	(10,000)
Accrued interest repayment	(74)
Loans write-off	(6,881)
Loans repaid	–
Interest accrued	16,068
At 31 October	**–**

See note 33.3 in Section B of Part 13 *"Consolidated Historical Financial Information"*.

Mathios Rigas

Growthy Holdings is beneficially owned and controlled by Mathios Rigas, the CEO of the Group. Growthy Holdings provided shareholder funding in the amount of US$4.8 million to Energean Israel in August 2016 in connection with the financing of the acquisition of the acquisition of the Karish and Tanin Leases. This loan was converted into EISL Class B Shares in Energean Israel pursuant to the EISL Subscription Agreement. These EISL Class B Shares were acquired by the Company on 15 March 2018 in exchange for US$4.8 million in cash in accordance with the terms of the Supplementary Agreement. In addition, Growthy Holdings acquired in 2015 a sub-participation interest of approximately 4% of the US$125 million shareholder loan made by Third Point to the Group. Energean International repaid this shareholder funding on 30 June 2017 by the issue of certain EIL Preference Shares on the terms of the Reorganisation Agreement. Growthy Holdings subsequently transferred such EIL Preference Shares to Third Point pursuant to the terms of the Supplementary Agreement.

See also paragraph 3.1 of this Part 9 "*Reorganisation in connection with Admission*".

Efstathios Topouzoglou

Oilco Investments is beneficially owned and controlled by Efstathios Topouzoglou, a non-executive Director. Oilco Investments provided shareholder funding in the amount of US$4.8 million to Energean Israel in August 2016 in connection with the financing of the acquisition of the Karish and Tanin Leases. This loan was converted into EISL Class B Shares in Energean Israel pursuant to the EISL Subscription Agreement. These EISL Class B Shares were acquired by the Company on 15 March 2018 in exchange for US$4.8 million in cash in accordance with the terms of the Supplementary Agreement. In addition, Oilco Investments acquired in 2014 a sub-participation interest of approximately 4% of the US$125 million shareholder loan made by Third Point to the Group. Energean International repaid this shareholder funding on 30 June 2017 by the issue of certain EIL Preference Shares on the terms of the Reorganisation Agreement. Oilco Investments subsequently transferred such EIL Preference Shares to Third Point pursuant to the terms of the Supplementary Agreement.

See also paragraph 3.1 of this Part 9 "*Reorganisation in connection with Admission*".

Panos Benos

Adobelero is beneficially owned and controlled by Panos, Benos, the CFO of the Group. Adobelero provided shareholder funding in the amount of US$0.5 million to Energean Israel in August 2016 in connection with the financing of the acquisition of the Karish and Tanin Leases. This loan was converted into EISL Class B Shares in Energean Israel pursuant to the EISL Subscription Agreement. These EISL Class B Shares were acquired by the Company on 15 March 2018 in exchange for US$0.5 million in cash in accordance with the terms of the Supplementary Agreement.

See also paragraph 3.1 of this Part 9 "*Reorganisation in connection with Admission*".

Third Point

In 2014 and 2015, the Group was funded by its largest shareholder, Third Point, through a five-year US$125 million loan which was increased to US$179.7 million in 2015.

This shareholder loan (in the amount of US$227.8 million) was extinguished in full on 30 June 2017 by the issue on 30 June 2017 of certain EIL Preference Shares to Third Point (in respect of its participation interest of approximately 92% of such loan) on the terms of the Reorganisation Agreement. On 15 March 2018, Third Point acquired the EIL Preference Shares held by Growthy Holdings and Oilco Investments and the Company then acquired all of the EIL Preference Shares in consideration for the issue of 9,270,038 Acquisition Shares on the terms of the Reorganisation Agreement (as amended by the Supplementary Agreement).

See also paragraph 3.1 of this Part 9 "*Reorganisation in connection with Admission*".

Kerogen

Pursuant to the Kerogen Interim Facility Agreement, Kerogen, as lender, provided a term loan of up to US$40 million to fund Energean Israel's acquisition of the Karish and Tanin leases and related costs. In June 2017, pursuant to the EISL Subscription Agreement and the EISL Shareholders Agreement, the facility was converted, together with a further equity investment by Kerogen of US$10 million in Energean Israel, to an approximately 50% equity interest in Energean Israel.

See also paragraph 12.7 of Part 16 "*Additional Information*".

3.4 Agreements with Kerogen

Energean E&P Holdings and Kerogen have entered into a number of agreements in respect of their shareholdings in, and funding of, Energean Israel. See paragraphs 12.7, 12.8 and 12.9 of Part 16 "*Additional Information*".

3.5 Other

In addition to the above, the Group has entered into a number of related party transactions for amounts and terms which are immaterial to the Group both individually and in the aggregate. *See note 33 to the financial information set out in Section B of Part 13 "Consolidated Historical Financial Information" for all material related party transactions.*

PART 10
SELECTED FINANCIAL INFORMATION

The selected financial information set out below has been extracted without material amendment from Section B of Part 13 "Consolidated Historical Financial Information" of this Prospectus, where it is shown with important notes describing some of the line items. Investors should read the whole of this Prospectus before making an investment decision and not rely solely on the summarised information in this Part 10.

Consolidated statement of profit or loss
(Amounts in thousands US$, unless otherwise stated)

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Revenue	38,425	31,187	39,724	28,434	42,244
Cost of Sales	(36,363)	(31,574)	(40,551)	(32,128)	(32,279)
Gross profit (loss)	**2,062**	**(387)**	**(827)**	**(3,694)**	**9,965**
Administration expenses	(4,339)	(3,305)	(4,134)	(4,788)	(6,241)
Selling and distribution expenses	(313)	(267)	(336)	(308)	(298)
Exploration and evaluation expenses	(7,050)	(1,116)	(1,133)	(252)	(308)
Other income	2,169	558	248	265	26,192
Other expenses	(9,770)	(1,735)	(4,688)	(3,061)	(7,482)
Operating profit (loss)	**(17,241)**	**(6,252)**	**(10,870)**	**(11,838)**	**21,828**
Finance Income	14	323	327	91	166
Finance Costs	(21,132)	(20,997)	(29,311)	(20,138)	(18,283)
Gain on derivative	24,109	—	—	—	—
Net foreign exchange gain/(loss)	27,621	499	(10,043)	(12,116)	(10,191)
Profit (loss) from continuing operations before tax	**13,371**	**(26,427)**	**(49,897)**	**(44,001)**	**(6,480)**
Taxation income / (expense)	(8,776)	7,066	11,517	10,581	(7,317)
Profit (loss) from continuing operations	**4,595**	**(19,361)**	**(38,380)**	**(33,420)**	**(13,797)**
Discontinued operations					
Profit/(loss) from discontinued operations	(1,403)	(108)	(229)	(66)	(104)
Profit (loss) for the period	**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**
Attributable to:					
Owners of the parent	3,201	(19,469)	(38,608)	(33,468)	(10,270)
Non-controlling Interests	(9)	—	(1)	(18)	(3,631)
	3,192	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**

Consolidated statement of financial position
(Amounts in thousands US$, unless otherwise stated)

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
ASSETS					
Non-current assets					
Property plant and equipment	290,318	236,367	230,180	201,009	166,304
Intangible assets	3,616	7,705	8,278	4,203	1,459
Investments in Joint Ventures	—	—	—	41	118
Other non-current assets	575	157	382	801	417
Deferred tax asset	16,761	17,789	20,678	10,751	—
Bank deposits	1,828	1,151	1,116	4,013	2,683
	313,098	**263,169**	**260,634**	**220,818**	**170,981**
Current assets					
Inventories	14,276	12,842	12,757	8,284	14,684
Trade and other receivables	11,716	24,915	13,739	12,162	10,753
Current tax assets	—	—	92	17	17
Cash and cash equivalents	6,835	23,491	11,861	4,225	11,644
Derivative asset	91,615	—			
Assets classified as held for sale	—	—	45,203	—	—
	124,442	**61,248**	**83,652**	**24,688**	**37,098**
Total assets	**437,540**	**324,417**	**344,286**	**245,506**	**208,079**
EQUITY AND LIABILITIES					
Equity attributable to owners of the parent					
Share capital	917	14,904	14,904	14,904	14,904
Equity reserves	62,981	115,214	117,080	114,690	122,329
Merger reserves	139,903	—	—	—	—
Retained earnings	(145,206)	(129,268)	(148,407)	(109,799)	(65,001)
Equity attributable to equity holders of the parent	**58,595**	**850**	**(16,423)**	**19,795**	**72,232**
Non-controlling interests	224,294	304	303	304	(12,906)
Total Equity	**282,889**	**1,154**	**(16,120)**	**20,099**	**59,326**
Non-Current Liabilities					
Borrowings	79,186	268,453	255,118	187,402	117,930
Deferred tax liabilities	3,732	3,878	2,989	3,813	3,863
Provisions for liabilities	6,749	3,992	4,665	3,071	3,044
Other long term liabilities	2,555	2,954	2,737	3,299	—
	92,222	**279,277**	**265,509**	**197,585**	**124,837**
Current Liabilities					
Trade and other payables	54,607	33,964	29,082	27,822	23,916
Borrowings	—	10,022	21,130	—	—
Liabilities directly associated with assets classified as held for sale	—	—	44,685	—	—
Current tax liabilities	2,605				
Provisions for liabilities	5,218				
	62,430	**43,986**	**94,897**	**27,822**	**23,916**
Total Liabilities	**154,652**	**323,263**	**360,406**	**225,407**	**148,753**
Total Equity and Liabilities	**437,540**	**324,417**	**344,286**	**245,506**	**208,079**

Consolidated statement of cash flows

(Amounts in thousands US$, unless otherwise stated)

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Operating activities					
Profit / (loss) before tax	11,968	(26,535)	(50,126)	(44,067)	(6,584)
Adjustments:					
Depreciation of property, plant and equipment	14,754	15,414	21,355	7,428	7,628
Amortisation of intangible assets	177	125	144	153	95
Share of results of joint ventures	—	—	—	66	104
Loss from the sale of Property, Plant and Equipment	—	1,589	1,577	—	—
Impairment loss on inventory	3	—	403	2,486	1,024
Impairment loss on property, plant and equipment	111	—	1,947	39	4,560
Impairment loss on intangible assets	6,646	—	—	61	199
Gain from disposal of subsidiary	(1,540)	—	—	—	—
Increase in provisions	9,754	297	738	567	175
Finance income	(14)	(323)	(327)	(91)	(166)
Finance costs	21,132	21,021	29,311	20,138	18,283
Gain from financial instruments	(24,109)	—	—	—	—
Write-off of portion of loans	—	—	—	—	(24,927)
Net foreign exchange gain / (loss)	(27,621)	(499)	10,039	12,339	12,092
	11,261	**11,089**	**15,061**	**(881)**	**12,483**
Changes in working capital:					
Inventories	(192)	(4,558)	(4,952)	3,905	(5,672)
Trade and other receivables	4,593	(10,509)	(1,530)	(1,409)	18,363
Trade and other payables	7,971	7,215	6,314	(3,623)	(8,016)
Other non-current assets	(193)	644	416	(384)	264
Cash flows from / (used in) operations	**23,440**	**3,881**	**15,309**	**(2,392)**	**17,422**
Tax paid	—	—	—	(28)	—
Payments in relation to provisions	—	—	(74)	(344)	(291)
Net cash from / (used in) operating activities	**23,440**	**3,881**	**15,235**	**(2,764)**	**17,131**
Investing activities					
Payment for purchase of intangible assets	(2,968)	(3,625)	(44,745)	(3,111)	(1,600)
Payment for purchase of property, plant and equipment	(41,045)	(52,443)	(65,935)	(46,080)	(34,249)
Disposal of subsidiary, net of cash disposed	(5,610)	—	—	—	—
Acquisition of subsidiary, net cash outflow	—	41	47	—	—
Payment for purchase of investments in joint ventures	—	—	(41)	(26)	—
Proceeds from disposal of property, plant and equipment	—	622	1,747	—	—
Proceeds from disposal of intangible assets	954	—	—	—	—
Interest received	14	19	83	91	166
Net cash used in investing activities	**(48,655)**	**(55,386)**	**(108,844)**	**(49,126)**	**(35,683)**
Financing activities					
Repayments of loans	—	(20,000)	(20,000)	—	(75,089)
Proceeds from new loans	21,250	90,472	127,312	47,359	112,500
Finance cost paid	(3,330)	(1,088)	(2,692)	(950)	(4,241)
Transaction costs	(718)	(1,466)	(1,564)	(385)	(9,765)
Net cash from financing activities	**17,202**	**67,918**	**103,056**	**46,024**	**23,405**
Net increase / (decrease) in cash and cash equivalents	8,013	16,413	**9,447**	**(5,865)**	**4,853**
Cash and cash equivalents at beginning of the period	17,586	8,238	8,238	14,327	11,286
Effect of exchange rate fluctuations on cash and cash equivalent	(910)	(9)	(99)	(224)	(1,812)
Cash and cash equivalents at end of the period	**8,663**	**24,642**	**17,586**	**8,238**	**14,327**
Current cash and cash equivalent	6,835	23,491	11,861	4,225	11,644
Non-current bank deposits	1,828	1,151	1,116	4,013	2,683
Current cash and cash equivalents held for sale	—	—	4,609	—	—
Cash and cash equivalent at end of the period	**8,663**	**24,642**	**17,586**	**8,238**	**14,327**
Supplemental cash flow information					
Non-Cash Investing and Financing Activities					
Settlement of loan for issuance of preference shares	230,564	—	—	—	—
Capitalization of depreciation to oil & gas properties	1,974	3,050	7,014	2,339	—
Capitalised borrowing costs	1,056	3,855	3,992	3,553	834

Key Performance Indicators

The Directors consider the following metrics to be the key performance indicators ("**KPIs**") used by the Group to help evaluate growth trends, establish budgets and assess operational performance and efficiencies. In addition to the Group's results determined in accordance with IFRS, the Directors believe the KPIs are useful in evaluating the Group's operating performance.

See also *"Important Information—Non-IFRS financial information"*.

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Adjusted EBITDAX (*US$ 000*)*[1]	12,341	11,580	16,202	(1,209)	11,149
Free cash flow (*US$ 000*)*[2]	(20,573)	(52,187)	(95,445)	(51,955)	(18,718)
Total production for the period (*boe*)*[3]	808,377	1,047,529	1,273,751	532,624	514,218
Average production per day (bopd)	2,659[3]	3,435	3,490	1,459	1,409
2P reserves (*mboe*)[4]	51.0	29.8	41.0	29.8	30.3
2C resources (*mboe*)[4]	474.5	27.8	195.6	27.8	—
Cost of oil production*[5]	21,118	20,596	24,303	21,740	32,286
Cost of oil production per boe* (*US$*)[5]	26.12	19.66	19.08	40.82	62.79
Net debt*[6]	70,524	36,529	48,458	(7,017)	(12,965)
Gearing ratio (net debt/capital)*[6]	24.93%	16.72%	24.39%	-3.40%	-7.37%
LTIFR[7]	2.72	4.21	3.5	0.0	0.0
Realised sales price	43.02	33.40	34.25	43.57	95.90
Capital expenditure (*US$000*)	53,447	57,039	108,756	63,419	33,622

Notes:

* Denotes a Non-IFRS Measure

(1) Adjusted EBITDAX is calculated as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange gain/(loss) and exploration and evaluation expenses. The table below sets forth a reconciliation of Adjusted EBITDAX with profit/(loss) for the period.

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$000		
Adjusted EBITDAX	**12,341**	**11,580**	**16,202**	**(1,209)**	**11,149**
Total depreciation**	(14,754)	(15,414)	(21,355)	(7,428)	(7,628)
Amortisation of intangible assets	(177)	(125)	(144)	(153)	(95)
Exploration and evaluation expenses	(7,050)	(1,116)	(1,133)	(252)	(308)
Other income	2,169	558	248	265	26,192
Other expenses	(9,770)	(1,735)	(4,688)	(3,061)	(7,482)
Finance income	14	323	327	91	166
Gain on derivative	24,109	—	—	—	—
Finance costs	(21,132)	(20,997)	(29,311)	(20,138)	(18,283)
Net foreign exchange gain/(loss)	27,621	499	(10,043)	(12,116)	(10,191)
Profit/(loss) from continuing operations before tax	*13,371*	*(26,427)*	*(49,897)*	*(44,001)*	*(6,480)*
Taxation (expense)/income	(8,776)	7,066	11,517	10,581	(7,317)
Profit/(loss) from continuing operations	*4,595*	*(19,361)*	*(38,380)*	*(33,420)*	*(13,797)*
Profit/(loss) from discontinued operations	(1,403)	(108)	(229)	(66)	(104)
Profit/(loss) for the period	**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**

** Total depreciation is comprised of depreciation attributable to cost of sales and depreciation attributable to administration expenses.

(2) Free cash flow is defined as net cash from / (used in) operating activities less payment for purchase of intangible assets and payment for purchase of property, plant and equipment. The table below sets forth a reconciliation of free cash flow with net cash from / (used in) operating activities for the periods indicated.

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$000		
Net cash from / (used in) operating activities	23,440	3,881	15,235	(2,764)	17,131
Payment for purchase of intangible assets	(2,968)	(3,625)	(44,745)	(3,111)	(1,600)
Payment for purchase of property, plant and equipment	(41,045)	(52,443)	(65,935)	(46,080)	(34,249)
Free cash flow	**(20,573)**	**(52,187)**	**(95,445)**	**(51,955)**	**(18,718)**

(3) Production levels refer to total oil production for the periods. Oil volumes are STOB and include natural gas liquids. Average production per day for the ten month period ending 31 October 2017 would be 2,826 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down.

(4) 2P reserves and 2C resource figures as at 31 October 2017 include gas and liquids volumes as set out in the CPRs in *"Competent Persons' Reports"*, with gas volumes converted from Bcf at the rate of 5.8. Includes 100% of volumes set out in the Karish and Tanin CPR, of which the Group's working interest is 50%, expected to rise to 70% subject to taking FID by 31 March 2018 (or 30 June 2018 if Kerogen so consents), pursuant to the Second EISL Subscription Agreement. 2P reserves and 2C resource figures as at 31 October 2016 reflect the then most recent prior report dated as of 31 December 2015.

(5) Cost of oil production is defined as cost of oil sales, less cost of services, depreciation and change in inventory (defined as the difference between opening inventory and closing inventory) divided by total production for the period. The table below sets forth a reconciliation of cost of oil production with cost of sales for the periods indicated. Cost of oil production per boe is defined as cost of oil production divided by total production for the period.

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Cost of sales	35,744	31,574	40,551	32,128	32,279
Less					
Depreciation	(14,480)	(15,261)	(21,218)	(7,292)	(7,424)
Change in inventory	(146)	4,283	4,970	(3,096)	7,431
Cost of oil production	21,118	20,596	24,303	21,740	32,286
Total production for the period (boe)	808,377	1,047,529	1,273,751	532,624	514,218
Cost of oil production per boe (*US$*)	**26.12**	**19.66**	**19.08**	**40.82**	**62.79**

(6) Net debt is defined as the Group's total borrowings (including current and non-current borrowings), less shareholders' subordinated debt, cash and cash equivalents and bank deposits. Shareholders' subordinated debt is defined as loans from shareholders of the Group as set out in note 17 to the Consolidated Historical Financial Information. Capital is defined as the Group's total equity, plus shareholders' subordinated debt. The gearing ratio is calculated as net debt divided by capital.

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			000 US$		
Current borrowings	—	10,022	21,130	—	—
Non-current borrowings	79,186	268,453	255,118	187,402	117,930
Total borrowings	79,186	278,475	276,248	187,402	117,930
Less: Shareholders' Subordinated Debt	—	(217,304)	(214,813)	(186,181)	(116,568)
Less: Cash and cash equivalents and bank deposits	(8,663)	(24,642)	(12,977)	(8,238)	(14,327)
Net Debt[1]	70,524	36,529	48,458	(7,017)	(12,965)
Total equity	282,895	1,154	(16,114)	20,099	59,326
Plus: Shareholders Subordinated Debt	—	217,304	214,813	186,181	116,568
Capital[2]	282,895	218,458	198,693	206,280	175,894
Gearing Ratio (1/2):	24.93%	16.72%	24.39%	-3.40%	-7.37%

(7) LTIFR is defined as lost time incidents frequency rate, a metric of the Group's health and safety performance. Frequency rate is calculated on the basis of all recordable LTI multiplied by 1 million and divided by the total man-hours.

PART 11
OPERATING AND FINANCIAL REVIEW

This Part 11 "Operating and Financial Review" should be read in conjunction with Part 2 "Important Information", Part 5 "Business Overview", Part 6 "Overview of Israeli and Greek Oil and Gas Industry" and Part 13 "Consolidated Historical Financial Information". Prospective investors should read the entire document and not just rely on the summary set out below. The financial information considered in this Part 11 "Operating and Financial Review" is extracted from the financial information set out in Section B of Part 13 "Consolidated Historical Financial Information".

The following discussion of the Group's results of operations and financial conditions contains forward-looking statements. The Group's actual results could differ materially from those that it discusses in these forward-looking statements. Factors that could cause or contribute to such differences include those discussed below and elsewhere in this Prospectus, particularly under Part 1 "Risk Factors" and Part 2 "Important Information". In addition, certain industry issues also affect the Group's results of operations and are described in Part 6 "Overview of Israeli and Greek Oil and Gas Industry".

1. Overview

Energean is an independent oil and gas E&P company focused on the exploration, development and production of oil and gas assets in the Eastern Mediterranean, including Greece, Israel, the Adriatic and North Africa. Energean's strategy is to create a profitable and returns-focused business with sustainable growth by leveraging the Group's experience and expertise in identifying, acquiring, developing and operating oil and gas assets in this region. The Directors intend that the Company will, in due course, become the leading independent E&P company in the Eastern Mediterranean.

Since its establishment in 2007, Energean has acquired a diverse portfolio of producing assets, appraisal and development opportunities and exploration prospects and is the operator of the majority of the key assets in its portfolio. Energean's total 2P reserves are 50.0 MMbbls of oil and 6.0 Bcf of gas and its total 2C resources are 55.8 MMbbls of oil and 2.4 Tcf of gas as of 31 October 2017 (of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement).

For the ten months ended 31 October 2017, the Group had total revenue of US$38.4 million, with an operating loss of US$17.2 million. For the years ended 31 December 2016, 2015 and 2014, the Group reported total revenue of US$39.7 million, US$28.4 million and US$42.2 million, respectively, with operating loss of US$10.9 million in 2016, operating loss of US$11.8 million in 2015 and operating profit of US$21.8 million in 2014.

2. Significant factors affecting the Group's results of operations

2.1 Oil and gas prices

Oil and gas prices have a significant impact on the Group's revenue and, to a lesser extent, the Group's cost of sales. Historically, the Group has engaged in limited forms of hedging related to oil and gas prices.

Revenue

Crude oil prices

The Group currently depends on crude oil sales from its producing assets in the Prinos basin, which accounted for 97.8% of the Group's revenue in 2016 and 97.2% in the first ten months of 2017. The price the Group is able to obtain for its crude oil under the BP Offtake Agreement significantly affects the Group's revenues and cash flow generation. In 2015, for example, the value of Group's crude oil sales decreased significantly due to a decline in realised oil prices in the period.

Under the terms of the BP Offtake Agreement, the Group sells the crude oil it produces from the Prinos, Prinos North and Epsilon fields (Greece) to BP, and the Group is entitled to continue to sell, and BP to buy, all oil produced from those fields until the later of 1 November 2025 or the delivery of 25 MMbbls. The Group has the right to call on BP to take delivery ("**lift**") when storage at the Group's storage tanks is at 350,000 bbls (capacity is 500,000 bbls), to enable the Group to manage available storage capacity.

The pricing formula in the BP Offtake Agreement provides for a differential to the dated Brent crude price based on a number of factors. For more information on the BP Offtake Agreement pricing formula, see *"Business Overview—Offtake and Marketing—BP Offtake Agreement*". In addition, BP has the option to choose the pricing month for the oil delivered, either the month of or the month prior to lifting. As a result of these provisions, as well as the irregular lifting schedule and amount of lifting in the year (ranging between 4 and 5 times per annum at current production levels), sales of the Group's crude oil have historically been at a discount to the average annual Brent crude oil price. In addition, because part of the pricing formula is fixed in dollar terms, the differential is proportionally larger when the underlying oil price is lower (as the fixed discount amount accounts for a larger proportion of the lower oil price). The table below summarises the average realised price for the Group's crude oil and the applicable discount to the Brent price for the financial years ended 31 December 2016, 2015 and 2014 and the ten months ended 31 October 2017. The Group is aiming to partially manage this price risk through limited short term hedging as explained below.

	Year ended 31 December	Ten months ended 31 October	Year ended 31 December		
	2017	2017	2016	2015	2014
Average realised price US$/bbl	46.73	43.02	34.25	43.57	95.90
Brent Average US$/bbl	54.19	52.41	43.78	52.39	98.95
Discount to Brent (%)	13.8%	19.8%	21.8%	16.8%	3.1%
Discount to Brent US$/bbl	7.46	9.39	9.53	8.82	3.05
Net Hedging Income /(loss) per bbl sold US$/bbl	(0.25)	—	(0.45)	3.72	1.60
Discount to Brent (including Hedging) US$/bbl	7.71	9.39	9.98	5.10	1.45
Discount to Brent including Hedging (%)	14.2%	17.9%	22.8%	9.7%	1.5%

Gas prices

Prospectively, the Group's projected revenues and the success of its business model will also depend on the price the Group is able to obtain for the natural gas it expects to produce, beginning in 2021, from the Karish and Tanin fields in Israel. The Group has to date signed Gas Supply Agreements relating to supply, subject to applicable conditions, of gas in an aggregate amount, following initial commissioning and transition periods, of approximately 4.2 BCM per annum on an ACQ basis (or 3.1 BCM per annum on a take or pay basis), excluding the Or Gas Supply Agreement (up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis or approximately 3.3 to 3.8 BCM per annum on a take or pay basis including the Or Gas Supply Agreement), assuming, inter alia, 95% uptime and reasonable maintenance. The contract price under the agreements is predominantly linked to Israeli electricity market costs, but with a small percentage (less than 5%) of the contracted quantity indexed to oil, and in each case underpinned by a price floor. While such contracts contain floor prices, the price the Group will receive for its gas under such contracts is variable and linked to market prices for natural gas through the Israeli electricity production component index and to Brent oil prices, thereby exposing the Group to gas and, to a more limited degreed, oil price volatility. The Group's lease rights in respect of the Karish and Tanin fields (as well as the sale and purchase agreement under which the leases were acquired) prohibit the Group from exporting gas produced from these fields outside of Israel, thereby limiting the Group to selling gas solely to the domestic Israeli market. The export limits further expose the Group to the effects of any fluctuations in gas prices in the Israeli domestic market. At this time it is not possible to assess the potential conditions or likelihood under which Energean might be granted an export quota with respect to the Karish and Tanin discoveries.

Cost of sales

As electricity and fuel have historically been the second largest cost of crude production for the Group, the Group's cost of sales is also exposed directly (as a purchaser of gas requirements beyond what is supplied by its own operations) and indirectly (as a purchaser of electricity) to the market price for gas. An increase in gas prices may therefore increase the Group's cost of sales, negatively impacting the Group's profitability.

Hedging activity

The Group does not have a formal hedging policy with regard to oil or gas prices and is limited in the scope of its hedging activities under the terms of its facility agreements. When the Group has engaged in hedging activity, it is for limited volumes and for short periods (less than 365 days). Historically, hedging of oil prices has been undertaken via zero cost collars for general downside risk and fixed price contracts to set a fixed price for a set number of barrels for a known future BP lifting to protect against either (i) a fall in the oil price and/or (ii) the pricing optionality afforded to BP under the BP Offtake Agreement. From 2014 to 2017, the Group hedged

approximately 700,000 barrels or 21.1% of crude sales in the period. The table below represents the yearly portion of the crude hedged over the total crude sold to BP:

Period	Crude sales (bbls)	Crude hedged (bbls)	Crude Hedged over Crude Sales (%)
2014	419,755	150,000	36%
2015	577,047	300,000	52%
2016	1,133,987	150,000	13%
2017	1,179,368	100,000	8.5%
Total	**3,310,157**	**700,000**	**21.1%**
1 Jan. to 31 Oct. 2017	850,034	—	0%

Hedge gains and losses are recorded within revenue. The Group realised a gain of US$0.6 million and US$1.9 million on zero cost collars in 2014 and 2015 respectively (with no zero cost collars in 2016) and gains of US$0.1 million and US$0.3 million and a loss of US$0.5 million in 2014, 2015 and 2016 respectively. As of 31 October 2017, the Group was not engaged in any hedging activity with respect to the oil or gas prices. The Company did not apply hedge accounting.

For additional information on oil and gas price risks, see "*Risk Factors—Risks relating to the Group's business—The Group's current business depends significantly on the level of oil prices, which are volatile, and could be adversely affected by a substantial or extended decline in oil prices"* and *"Risk Factors—Risks relating to the Group's business—The Group will be generally prohibited from exporting Karish and Tanin gas production outside of Israel and as a result is subject to risks and uncertainties in the domestic Israeli gas market"*.

2.2 Production volumes

The Group's production volumes also have a significant impact on the Group's results of operations, affecting its revenue and costs per unit of production. Historically, the Group's crude oil production volumes from the Prinos basin have had the most significant impact on the Group's results of operations. Prospectively, gas production volumes will have a more significant impact as gas production from the Group's Karish and Tanin fields is expected to begin in 2021 and, over time, is expected to account for the majority of the Group's revenue.

The table below presents information on the Group's oil and gas production for the years ended 31 December 2014, 2015 and 2016, the ten month period ended 31 October 2017 and full year 2017.

	Year ended 31 December	Ten months ended 31 October	Year ended 31 December		
	2017	2017	2016	2015	2014
Average daily oil production for the period (bopd)[1]	2,803[3]	2,659[4]	3,490	1,459	1,409
Average daily gas production for the period (Nm^3pd)[2]	1,882	2,260	1,802	5,104	5,402
Total oil production for the period (kbbls)[1]	1,023	808	1,274	533	514
Total gas production for the period (000 Nm^3)[2]	687	687	658	1,863	1,972
Total oil sales volume for the period (kbbls)[1]	1,179	850	1,134	577	420

Notes:

(1) All oil production occurred at the Group's Prinos and Prinos North offshore fields in Greece. Oil volumes refer to standard oil barrels ("**STOB**") and include natural gas liquids.

(2) Gas production volumes indicated do not include associated gas production, produced as a by-product of the Group's oil production and reinjected during production at Prinos and Prinos North. No gas was sold during the period.

(3) 2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down.

(4) 2,826 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down.

The Group's total crude oil production averaged 1,459 bopd in 2015 and 1,409 bopd in 2014, and monthly averages fluctuated between 1,128 bopd and 2,388 bopd in 2014 and 2015, with the exception of October 2014, where production averaged 449 bopd due to a planned full shut down of operations for 13 days for maintenance. In 2016, three new wells were drilled at Prinos, and three new producing wells were brought online, providing an incremental rise in production to 3,490 bopd. The subsequent increase in sales volume resulted in an increase in revenue in 2016, despite a reduction in the realised price for the Group's crude oil. Total production from 2014 to 2016 was 2.3 MMbbls, compared to sales volume of approximately 2.1 MMbbls. The Group's policy is to retain 58 kbbls at all times to protect the lining of the storage tanks.

In the ten month period ended 31 October 2017, the Group produced an average of 2,659 bopd (2,826 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down), below previous projections, reflecting production difficulties relating to asphaltene problems, production shutdown for 18 days in September-October 2017 and issues with the Group's drilling strategy, which resulted in only two additional wells coming online in 2017 rather than the four previously anticipated. For the year ended 31 December 2017, average production was 2,803 bopd (2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down). For information on the 2017 production difficulties, see *"Business overview—Overview of assets—Greece—Prinos—Field technical background"*. The Group is addressing the completion issues, with three of four problematic dual designs now replaced, and are focused on rebuilding production, which averaged 3,405 bopd in the three months ended 31 December 2017. Energean estimates average daily 2P production rates to increase to 4,864 bopd in 2018 as per the NSAI CPR as new infill wells are brought on stream in Prinos complex.

Total gas production during the period decreased from 1,972,000 Nm^3 in 2014 (average 5,402 Nm^3pd) to 658,000 Nm^3 in 2016 (average 1,802 Nm^3pd), reflecting the depletion of the South Kavala field in 2016. In the ten months ending 31 October 2017, total gas production was 687 Nm^3 (average 2.260 Nm^3pd) and for the year ended 31 December 2017 687 Nm^3 (average 1.882 Nm^3pd). Associated gas production (gas production as a by-product of oil production) increased from 3,090,474 Nm^3 in 2014 to 7,896,460 Nm^3 in 2016 as a result of increased oil production, and was 5,687,991 Nm^3 in the ten months ended 31 October 2017 and 7,561,921 Nm^3 in the year ended 31 December 2017. This gas was primarily used in the production of the Group's oil and not sold to third parties. The Group also produces sulphur as a by-product of the associated gas stream associated with its oil production. Energean has a contract for the sale of sulphur whose initial term ran until 3 January 2018 and prices the sulphur on the basis of a monthly average of the fob Med (under 10k) price, as published by the Argus FMB Weekly Price, discounted by 20%. The contract provides for an annual renewal. Upon the expiration of the initial term or any renewal thereof, the contract is automatically renewed for a one year period unless, at least three months prior to the renewal date, either party gives the other party written notice of its intent not to continue. The Group produced 17,989 MT of sulphur in 2016, compared to 8,627 MT in 2015 and 7,449 MT in 2014, and sulphur sales accounted for 3.5% of revenues in 2016. The Group produced 12,147 MT of sulphur in the ten months ended 31 October 2017 and 15,070 MT for the year ended 31 December 2017.

Through its ongoing drilling and development program, the Group aims to increase production volumes from its fields in the Prinos basin. The Group produced approximately 3,490 bopd in 2016 and, despite a production slowdown in the first half of 2017, is targeting 12,899 bopd by 2021 as estimated in the NSAI Prinos CPR. The Group expects that production from the Prinos basin will peak at this level before gradually declining after 2021. Following first gas from Karish, expected in 2021, the Group aims to ramp up production volumes from Karish and Tanin to approximately 33.6 mmboe (or 92,000 boepd) in 2021 as estimated in the NSAI Israel CPR.

The Group's Prinos, Prinos North and South Kavala fields are mature fields, and while the Group hopes to increase production from the Prinos and Prinos North fields in the near to medium term, production from these fields can be expected to decline over the longer term. Similarly, while the Group hopes to bring new production online at its Epsilon oil field and Karish and Tanin gas fields, such production will also decline over the life of these fields and the duration of their productive life cannot be known with certainty. To the extent production volumes from these fields decrease in the future, such will have a negative impact on the Group's revenues and cost structure as discussed above. See "*Risk Factors—Risks relating to the Group's business—The level of the Group's crude oil and gas reserves and resources and their quality and production volumes and expected cash flows are inherently uncertain and may be lower than estimated or expected.*"

Cost base relative to production

Oil and gas exploration and production is a resource intensive business, involving high fixed costs relating to property, plant and equipment capital expenditure and related financing, depreciation and maintenance expenses. In particular, as of 31 October 2017, the Group had invested approximately US$173.3 million since 1 January 2015 in the ongoing development program at the Prinos, Prinos North and Epsilon fields and expected to invest an additional approximately US$353 million from 2018 through 2021 and approximately US$65 million from 2021 to 2034. Total investment in Prinos to date was approximately US$446 million as of 31 October 2017. The Group also expects to make other significant investments going forward, particularly through the development plan for the Karish and Tanin fields of approximately US$1.6 billion in Phase 1 capex (plus an additional US$371 million in other costs, including deferred payments). For further information on the Group's planned development expenditure, see *"—Development costs"*, *"—Liquidity and capital resources—Capital expenditure"*, *"Business Overview—Overview of assets"* and *"Business Overview—Field development for the Prinos Basin"*. The cost of these investments must be recouped through subsequent production. Similarly, while

the Greek state owns the majority of the facilities the Group relies on for its production in the Prinos basin, the Group must operate and maintain these assets for intended use. In the historical period, maintenance costs for the platform, pipeline, and Sigma plant were between US$5.2 million to US$7.9 million annually, excluding personnel and energy costs. Some of these assets have historically been significantly underutilised. In particular, the Sigma processing plant operated at only around 13% of capacity in 2016 and 10% in 2017, representing a relatively high fixed cost base. A cost efficiency program and increased production have improved operational efficiency in the period under review and the Group hopes to continue this trend through expected increases in production. Other costs which may be fixed for certain periods include operating leases, such as those for the use of the Valiant Energy and Energean Wave vessels, which provide for annual charter fees of US$6.4 million through November 2018.

Such high fixed costs mean that total costs per unit of production are, in general, negatively correlated with production volumes. Accordingly, the Group's profit per unit of production at a given price level is generally higher when production volumes are high and lower when production volumes are low (or loss-making, as has been the case during the periods under review). When production volumes are low, the Group may be more vulnerable to a decline in the realisable price for its oil or gas as its higher costs per unit of production dictate a higher break-even price.

The fixed costs involved in acquiring, upgrading and maintaining certain key assets can potentially reduce variable operating costs. For instance, capital expenditure in the Prinos basin to date has included the US$8.75 million acquisition of the Energean Force in 2014 and its subsequent €20.9 million (approximately US$23.3 million) refurbishment. By using its own rig, specifically equipped and staffed for Energean's purposes, the Group has reduced its reliance on external rig contractors and minimised standby charges and mobilisation fees, reducing the cash cost of its rig operations, while achieving high operational efficiency and focus to the extent that higher production volumes can be achieved and maintained.

The Group's average cost of oil production per barrel (as described below under *"—Key operating costs"*) decreased during the period, from approximately US$63 per barrel in 2014 to US$41 in 2015, US$19 in 2016 largely as a result of increased production volumes, given the high proportion of fixed costs. Average cost of oil production per barrel increased to US$26 in the ten months ended 31 October 2017, reflecting a decrease in production volume and shut down expenses associated with the 2017 facilities turnaround (see *"—Infrastructure—2017 Facilities Turnaround"*).

2.3 Key operating costs

The Group's operating costs affect its results of operations and factor in to the price per barrel that it must realise to continue its operations. Key operating costs relating to the Group's cost of oil production include certain staff costs, electricity and fuel, consumptions (comprising spare parts, chemicals and other materials used in production and plant maintenance), machinery repairs and maintenance, subcontracted work, insurance, sundry expenses (such as equipment rental) and royalties. These costs constitute the Group's cost of oil production which, together with inventory and depreciation, amount to cost of sales. For a breakdown, see note 23 in "*Consolidated Historical Financial Information*". The Group's cost of oil production (excluding depreciation) increased by 11.8% in 2016 to US$24.3 million, compared to US$21.7 million in 2015 and US$32.3 million in 2014, principally reflecting changes in staff costs and electricity and fuel costs. Such cost of oil production increased by 2.5% in the ten months ended 31 October 2017 to US$21.1 million, compared to US$20.6 million in the ten months ended 31 October 2016, principally reflecting increases due to planned full shut down activities.

Other costs include administration expenses, selling and distribution expenses and exploration and evaluation expenses. These costs together increased by 4.8% in 2016 to US$5.6 million, compared to US$5.3 million in 2015 and US$6.8 million in 2014, principally reflecting changes in staff costs and, in 2016, an increase in exploration and evaluation expenses. These costs together increased by 149.6% in the ten months ended 31 October 2017 to US$11.7 million, compared to US$4.7 million in the ten months ended 31 October 2016, principally reflecting impairment of exploration expenditure in West Kom Ombo in Egypt.

Staff cost

Staff costs have historically been the largest cash cost item in the Group's operations, accounting for 28.6% of cost of sales and 48.1% of administration expenses in 2016 and 30.1% of cost of sales and 44.6% of administration expenses in the ten months ended 31 October 2017. During the historical period, staff costs were paid principally in Euro. The Group's staff costs relate to those involved in production activities as well as selling, administrative and other supporting functions and directors' remuneration. Certain of these costs are

presented as expenses under cost of sales, administration expenses, selling and distribution expenses, or other expenses depending on the function to which they relate. Certain other costs are capitalised in accordance with IFRS to the value of oil and gas assets and exploration and evaluation costs. Staff costs up to 2016 are presented net of payroll subsidies that the Group believes it is owed by the Greek Public Body for Employment and Social Inclusion. The Group has not received payment of such subsidies since 2013, but it recognises the accrued value of such government subsidies for the period from the second half of 2010 to 31 December 2015 under trade and other receivables on its balance sheet as described in note 12 in *"Consolidated Historical Financial Information"*. For more information on payroll subsidies, see *"Additional Information—Litigation"*.

The Group's total payroll cost decreased by 27.6% from 2014 to 2015, followed by an increase of 7.8% from 2015 to 2016. The 2015 decline was driven in part by a decrease of average wages and salaries in 2015 due to a 6% wage cut and suspension of overtime for KWA employees (representing around 63% of the Group's employees in 2016) introduced in 2014 in response to reduced production and the Greek financial crisis. Total payroll cost increased in 2016, driven by increased headcount. There was also an increase to 30.3% in 2015 (and 30.5% in 2016) in the proportion of certain staff costs (including wages and salaries, social insurance and other funds, and other staff costs) that were capitalised, compared to 12.0% in 2014, reflecting development activities related to Prinos infill drilling and Epsilon platform development. In March 2017, following increased production, the KWA negotiated a reversal of the 2014 pay reduction to be applied retrospectively from 1 January 2017, though overtime compensation has not been reinstated and permission to work overtime is only granted in exceptional circumstances. The adjustments in respect of January and February salaries were made in two instalments in May and June 2017.

The composition of the Group's employee mix also changed during the period, with 69 additional drilling and supply boat staff added from 2014 to 2016, reflecting the activation of the Valiant Energy vessel in 2014 and the Group's move to staff the Energean Force rig with full time employees along with contract workers.

The Group also maintains a defined benefit pension plan for its employees, which is unfunded. As of 31 October 2017, the Group's defined benefit obligation was US$2.9 million, compared to US$2.5 million in the ten months ended 31 October 2016. For information on the Group's defined benefit plan, see note 20 in "*Consolidated Historical Financial Information*".

Electricity and fuel cost

Electricity and fuel expense has historically been the second largest cost of production, accounting for 14.8% of cost of sales in 2016 and 13.3% of cost of sales in the ten months ended 31 October 2017. The Group requires gas and electricity to run the facilities that process the crude oil it produces. While the Group supplies some of its gas requirements from its own production, the Group has historically met shortfalls between the gas required for crude production and its gas produced by purchasing gas from third parties. Gas is provided on an annual fixed-price contract at a commercial discount. In 2016, associated gas production increased significantly due to an increase in oil production in the Prinos basin, resulting in a high decrease of gas purchase from DEPA, the Public Gas Corporation of Greece. The Group purchased 3,091,096 Nm^3 of gas in 2016, compared to 5,508,119 Nm^3 in 2015, and 9,046,715 Nm^3 in 2014. In 2015, there was a reduction in overall gas consumption as a result of the impact of an energy efficiency program involving modifications to the processing plant in 2014 that reduced the amount of gas required per barrel of crude produced. This efficiency program was ramped up in 2016, achieving additional cost saving per barrel. Gas prices paid by the Group declined by 19.6% from 2014 to 2016, in line with commodities pricing for the period. Electricity tariffs also increased in 2016 due to new EU emissions legislation, contributing to an increase in electricity expense by 10.7% in 2016 as compared to 2015. In the ten month period ended 31 October 2017, the Group purchased 3,619,686 Nm^3 of gas, compared to 2,639,666 Nm^3 in the ten month period ended 31 October 2016. Gas prices paid by the Group declined by 31.8% from 2016 mainly due to improved, revised pricing under the long term contracts between PGC and its vendors. Electricity tariffs increased by 2.2% in the ten month period ended 31 October 2017 as compared to the ten month period ended 31 October 2016 due to an increase in the Public Electric Company price and CO_2 emissions back charged cost. The table below sets out the Group's total gas fuel and electricity charges for the years ending 31 December 2016, 2015 and 2014 and the ten months ended 31 October 2017.

	For the ten months ended 31 October		For the year ended 31 December (US$ 000)		
	2017	2016	2016	2015	2014
Gas fuel	1,274	1,364	1,491	2,426	5,424
Electricity	3,507	3,713	4,423	3,199	3,971
Utilities (water)	73	84	100	86	78
Total	**4,854**	**5,161**	**6,014**	**5,711**	**9,474**

Depreciation

The Group's depreciation expense relates mainly to its oil and gas properties. Oil and gas properties are depreciated on a unit of production basis over the 2P commercial reserves of the field they relate to. For the purposes of calculating depreciation, the value of oil and gas properties includes both historical capital expenditure and estimated future capital expenditure related to the development of undeveloped 2P reserves. Thus, the Group's depreciation expense may change across periods based on the Group's assumptions regarding the future development costs necessary to access its 2P reserves, in addition to other assumptions regarding factors such as oil prices, reserves and operating expenditure. In 2016, a revised estimate of necessary future capital expenditure, reflecting the Group's estimates as of 31 December 2016 of development costs at its Prinos basin fields, contributed to a substantial increase in depreciation charges for the year. Estimated future capital expenditure as of 31 October 2017 increased by 6.4% over the level as of 31 December 2016.

Depreciation is also affected by management assumptions regarding the useful life of its assets. In 2016, the Group extended the assumed useful life of its oil and gas properties from 2028 to 2030, reflecting increases in 2P reserves and future Brent prices. As of 31 October 2017, the Group had extended the assumed useful life of oil and gas properties to 2032. For assets whose useful life is shorter than the lifetime of a field, the straight-line method of depreciation is applied so as to write off the cost or revalued amount of each asset to its residual value over its useful life. For additional information on the Group's depreciation policies, see note 3.5 in "*Consolidated Historical Financial Information*".

Total depreciation expense, excluding capitalised depreciation, amounted to US$21.5 million in the year ended 31 December 2016, US$7.6 million in the year ended 31 December 2015 and US$7.7 million in the year ended 31 December 2014. Total depreciation expense decreased by 3.9% in the ten months ended 31 October 2017 to US$14.9 million, compared to US$15.5 million in the ten month period ended 31 October 2016, principally reflecting an increase in estimated future 2P reserves. In addition, the Group capitalised depreciation amounting to US$2.0 million in the ten months ended 31 October 2017, compared to US$3.0 million in the ten months ended 31 October 2016. The group capitalised depreciation of US$7.0 million in the year ended 31 December 2016, compared to US$2.3 million in 2015 and nil in 2014 reflecting depreciation attributable to the Energean Force, which the Group acquired in 2014.

The substantial increase in the Group's depreciation expense in 2016 was attributable primarily to an increase in production volumes, representing an increase in the units of production in respect of which depreciation was realised for the period and revision of the estimate of necessary future capital expenditure.

2.4 Financing costs

The Group funded its operations principally through borrowings in the period. The Group's total borrowings as of 31 October 2017 were US$79.2 million, comprised of US$77.9 million in bank loans and US$1.3 million in other loans from third parties. As of 31 December 2016, the Group had US$320.5 million in total borrowings (including US$44.3 million in borrowings attributed to Energean Israel as an asset held for sale), of which US$259.1 million was owed to shareholders or Kerogen and US$61.4 million was owed to third parties. As of 31 December 2015, the Group had US$187.4 million in total borrowings, of which US$186.2 million was owed to shareholders, as compared to total borrowings of US$117.9 million as of 31 December 2014, of which US$116.6 million was owed to shareholders. For further details of the Group's borrowings during the period, see notes 17 and 33 in "*Consolidated Historical Financial Information"*.

In April 2014, Energean Holdings and EOGSA signed an agreement with Piraeus Bank for a discounted cash settlement of the amount of US$56.0 million for all outstanding loans of the Group as of 31 December 2013. The Group recognised the remaining balance, US$24.9 million, as other income for the Group.

In 2014 and 2015, the Group was funded principally by its largest shareholder, Third Point Capital, through a five-year US$125 million loan which was increased to US$179.7 million in 2015 (the "**Third Point Shareholder Loan**"). On 30 June 2017, this loan was discharged in consideration for the issuance of preference shares in Energean International, which were acquired by the Company as set out in the Reorganisation Agreement on 15 March 2018 in consideration for the issue of 9,270,038 Acquisition Shares.

In May 2016, EOGSA obtained a US$75 million senior secured facility from EBRD, amended in July 2016, to fund its drilling and work program in the Prinos area (the "**EBRD Senior Facility**") and a subsequent US$20 million subordinated facility, amended in March 2017, to help fund its exploration activities (the "**EBRD Subordinated Facility**").

In December 2016, Kerogen Capital agreed to invest US$50 million in Energean Israel, comprising a US$40 million convertible loan paid in 2016 and the first quarter of 2017 (the "**Kerogen Interim Facility**") and a further US$10 million paid in June 2017. Energean Israel also obtained US$10 million in further loans from the Founders (the "**Founder Loans**") in 2016 to help fund its Karish and Tanin acquisition. Pursuant to the EISL Subscription Agreement dated 19 December 2016, the Kerogen Interim Facility and Founders Loans were discharged in consideration of the issue of shares in Energean Israel whereby Kerogen acquired a 49.9999% equity voting interest and a 50% economic interest and the Founders acquired a 50.0001% economic interest in Energean Israel. Pursuant to the Reorganisation Agreement and the Supplementary Agreement, the Company acquired the Founders' shares in Energean Israel on 15 March 2018 in consideration for US$10 million.

As a result of the above activities, the Group's finance costs increased by US$9.2 million, or 45.5%, to US$29.3 million in 2016 from US$20.1 million in 2015 and US$18.3 million in 2014. This increase was primarily the result of increased amortisation of related party loan interest and issuance fees in 2014 and 2015. Finance costs increased by 0.6% in the ten months ended 31 October 2017 to US$21.1 million, compared to US$21.0 million in the ten months ended 31 October 2016, principally reflecting a decrease in capitalisation of borrowing costs to assets.

On 30 January 2018, the EBRD Senior Facility was amended and restated to increase the facility amount up to US$180 million pursuant to the RBL Senior Facility Agreement in order to fund its ongoing drilling and development program. The RBL Senior Facility Agreement comprise two facilities: (a) a facility up to US$105 million comprising EBRD and Black Sea Trade and Development Bank as lenders; and (b) a Romanian club facility of up to US$75 million pursuant to which the Export-Import Bank of Romania Eximbank SA and Banca Comerciala Intesa Sanpaolo Romania S.A. will be lenders. For more information regarding the RBL Senior Facility Agreement, see Part 16 "*Additional Information—Material Contracts—Senior Borrowing Base Facility*".

Energean entered into a Senior Credit Facility of up to US$1.275 billion on 2 March 2018. The proceeds of the Senior Credit Facility, together with an estimated US$465.8 million equity contribution from the Group and Kerogen, expected deferred payments (post-2021) of US$140 million in respect of the Technip EPCIC Contract (as defined below) and related US$125 million standby letter of credit, will be used to fund Karish and Tanin Phase 1 project costs, interest and financing costs, and certain deferred payments to Delek and Avner (which have since merged together into Delek) pursuant to the terms of the Karish and Tanin sale and purchase agreement.

As a result of such additional borrowings, the Group's finance costs are likely to be higher in the future than in historic periods.

The Group is exposed to interest rate risk in relation to its borrowings, particularly its borrowings under the RBL Senior Facility Agreement and the Senior Credit Facility, which are subject to variable interest rates linked to LIBOR. An increase in the interest rates payable on its liabilities could significantly impact the Group's cash flows and results. For information on the Group's interest rate risk, see note 37.1 in *"Consolidated Historical Financial Information"*. The Group's EBRD Subordinated Facility also includes an EBITDA participation amount of up to 4.0% of EOGSA EBITDA payable to the EBRD when EOGSA's EBITDA is positive and certain other conditions are met. For these purposes, EOGSA's EBITDA is defined in the agreement as the total consolidated operating profit of the borrower before taking into account interest expense, taxes and extraordinary and exceptional items, and after adding back all amounts provided for depreciation and amortisation for such period, as shown in the most recent financial statements provided to the EBRD by EOGSA as set out in the agreement. The EBITDA participation amount shall accrue on a yearly basis from 1 January 2016 until 31 December 2024 and shall be payable in full on 25 August 2025. In addition, under the terms of the RBL Senior Facility Agreement and the EBRD Subordinated Facility, EOGSA and Energean E&P Holdings are subject to a number of negative and affirmative covenants, including prohibition of distributions and restrictions on the use of revenues related to the Prinos, Prinos North and Epsilon fields.

For further information on the Group's borrowings, see *"—Liquidity and capital resources—Capital resources—Borrowings"* and Part 16 *"Additional Information—Material Contracts"*.

2.5 Acquisitions and related commitments

The Group has incurred substantial costs related to the acquisition of oil and gas rights, and may make similar acquisitions in the future. The Group is also subject to minimum investment commitments under the terms of certain of the leases and concession agreements under which it operates. For further information on the Group's commitments under the leases and concession agreements, see *"—Commitments and contingent liabilities—Capital expenditure commitments"*.

Material lease acquisitions in the period under review include:

- In December 2016, Energean Israel acquired the Karish and Tanin offshore gas fields located in Israel (which are currently 50% owned by each of Energean and Kerogen Capital) for US$40.0 million closing payment with an obligation to pay contingent consideration of $108.5 million (contingent upon the final investment decision of Energean Israel Limited or aggregated expenditures of US$148.5 million in connection with the leases) and royalties to the sellers, plus VAT, which as of 31 October 2017 had an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of condensate and light oil (contingent 2C resources) (of which the Group's effective working interest is 50%, expected to rise to 70% subject to the terms and conditions of the Second EISL Subscription Agreement). All amounts are subject to Israeli VAT, with the US$40 million initial and closing payment and the US$108.5 million in deferred payments subject to a self-tax invoice and application of the reverse charge mechanism. As of 31 October 2017, the Group did not recognise a liability in respect of the deferred consideration as Energean has not triggered the clauses which will make this amount payable. The asset itself, recorded at a value equal to the US$40 million consideration paid, was included under assets held for sale at 31 December 2016 as described in note 9 in *"Consolidated Historical Financial Information."* The initial and closing payment of the acquisition and related costs were funded by US$10 million in loans from the Founders pursuant to the Founder Loans, US$40 million from Kerogen pursuant to the Kerogen Interim Facility, and a further US$10 million equity investment from Kerogen pursuant to the EISL Subscription Agreement, as discussed above. Subject to relevant regulatory approvals, and a final investment decision expected by the end of Q1 2018, the Group intends to invest US$1.6 billion in Phase 1 capex (plus an additional US$371 million in other costs, including deferred payments)to develop the field with a target of first gas in 2021. For further information on the acquisition of the Karish and Tanin fields, see *"Additional Information—Material contracts—Karish and Tanin sales and purchase agreement"*; for further information on planned development, see *"Business overview—Overview of assets—Israel."*
- In November 2016, Energean secured a 25-year exploitation licence for the West Katakolo offshore field, having in May 2014 signed two licence agreements with the Greek government for hydrocarbons exploration and exploitation in the Ioannina and Katakolo blocks. In the Ioannina block, the Group made an initial €7.9 million commitment which had, as of 31 October 2017, been reduced to €5.6 million (US$6.5 million). Pursuant to a March 2017 farm out agreement, Repsol will conduct the exploration of the Ioannina block, providing 90% of the committed investment up to US$25 million and 60% thereafter in exchange for a 60% interest. In the Katakolo block, the Group has received approval of an FDP and intends to make a final investment decision on the initial project phase following submission of an environmental and social impact assessment expected in 2018. The Group also has exploration and evaluation commitments at Katakolo of approximately US$0.3 million.

For further information on the Group's oil and gas leases, including certain other leases acquired during the period, see *"Business overview—Overview of assets"*. For further information on the Group's capital expenditure during the period, see *"—Liquidity and capital resources—Capital expenditure"*.

2.6 Accounting treatment of Energean Israel

Pursuant to the EISL Subscription Agreement dated 19 December 2016, the Group agreed to issue to Kerogen shares representing a 49.9999% equity voting interest and a 50% economic interest (representing 50% of EISL Class B Shares) in Energean Israel as repayment for Kerogen's US$50 million investment in Energean Israel. In addition, the Group agreed to transfer to the Founders shares representing the remaining 50% economic interest (representing 50% of EISL Class B Shares) in Energean Israel as repayment for the Founder Loans. As a result, Energean Israel was classified in the Consolidated Historical Financial Information as a discontinued operation for the year ended 31 December 2016. The share transfers occurred on 13 June 2017, and Energean Israel was classified as an investment in an associate with a 0% economic interest and accounted for under the equity method as of 31 October 2017, as reflected in the Consolidated Historical Financial Information. Pursuant to the EISL Shareholders' Agreement, while Energean has 50.0001% voting rights in Energean Israel, Energean must obtain consent from Kerogen regarding significant matters.

In the period ending 31 October 2017, a gain on derivative of US$24.1 million was driven by a provision for derivative valuation, measured at fair value at the end of each reporting date, which related to the EISL Class B Shares the Group expected to acquire. Pursuant to the Reorganisation Agreement, the Group had committed to acquire in an exit event 50% of the EISL Class B Shares of Energean Israel Limited held by the Founders. The valuation technique used to value this asset multiplies the estimated likelihood of an exit (being an IPO or a sale)

by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares to be acquired under the commitment. The change in fair value of US$24.1 million due to changes in measurement assumptions between 30 June 2017 and 31 October 2017 is included in gain on derivative in the consolidated statement of profit or loss. See note 36 in *"Consolidated Historical Financial Information*".

Pursuant to the Reorganisation Agreement, the Company acquired the Founders' 50% economic interest in Energean Israel on 15 March 2018 in exchange for US$10 million, leaving the Company with a 50% economic interest and 50.0001% voting rights in Energean Israel as of the date of this document. The Company's interest in Energean Israel is expected to change to 70%, Kerogen's interest to be reduced to 30%, in the first quarter of 2018 subject to the taking of FID by 31 March 2018 (or by 30 June 2018 if Kerogen so consents).

2.7 Development costs

The Group has incurred and will continue to incur substantial development costs, particularly with respect to the Karish and Tanin development in Israel, its ongoing operations in the Prinos Basin and potentially the development of the Katakolo field in Greece.

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells is capitalised within oil and gas properties. In addition, certain borrowing costs and depreciation costs are capitalised in oil and gas property and property under construction. The Group capitalises borrowing costs directly attributable to the acquisition, construction or production of qualifying assets. Borrowing costs include interest and loan expenses on an effective rate basis. The capitalised depreciation relating to depreciation of the drilling rig unit Energean Force for the period is related to drilling operation. The Group recorded additions to property, plant and equipment of US$62.7 million in 2016, compared to US$60.3 million in 2015 and US$32.0 million in 2014. The Group recorded additions to property, plant and equipment of US$50.6 million in the ten month period ended 31 October 2017. In the ten month period ended 31 October 2017, the Group's borrowing costs capitalised to assets amounted to US$1.1 million, compared to US$3.9 million in the ten month period ended 31 October 2016, US$4.0 million in the year ended 31 December 2016, US$3.6 million in 2015 and US$0.8 million in 2014. The Group capitalised US$2.0 million in depreciation to oil and gas properties in the ten month period ended 31 October 2017, compared to US$7.0 million in the year ended 31 December 2016, US$2.3 million in 2015 and nil in 2014 due to the extension of the useful life of Energean Force reflecting the extension of the Prinos drilling campaign.

Israel

The Group's principal anticipated development costs are in regard to the Karish and Tanin leases acquired by Energean Israel in August 2016.

Energean, in conjunction with its strategic partner Kerogen, has planned to develop the Karish and Tanin fields with a new-build FPSO, with estimated capital expenditure of US$1.6 billion and additional development costs of approximately US$371 million in Phase 1, the development phase running to first gas, expected in 2021. The share of net capital cost attributable to the Group's existing 50% interest to 2021, assuming 50% contributions from Kerogen, would amount to approximately US$233 million. If the Group acquires a further 20% interest in Energean Israel on the terms of the Second EISL Subscription Agreement, Kerogen's contribution would be reduced to approximately US$60 million. The Group's share of net capital cost attributable to a 70% interest to 2021, assuming 30% contributions from Kerogen, would amount to approximately US$405 million.

See also *"Risk Factors—Risks relating to the Group's business and industry—The Group's business strategy depends significantly on the successful development of the Karish and Tanin offshore gas fields in Israel, which are currently only at a preliminary stage of development"; "Risk Factors—Risks relating to the Group's business and industry—The Group's operations require significant capital expenditure, and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain and the costs of obtaining such finance may be significant"* and *"Risk Factors—Risks relating to the Group's business and industry—The Group faces significant uncertainties in connection with its exploration, appraisal and development activities, and it may discover or produce less oil or gas than expected*".

Greece

The Group is in the midst of a five-year drilling programme in the Prinos basin that has included acquisition and refurbishment of a drilling rig, Energean Force, infill drilling in Prinos and Prinos North and planned satellite

development of the Epsilon field. The program has been supported by financing from the EBRD. As of 31 October 2017, the Group had invested US$173.3 since 1 January 2015 and anticipated further expenditure from 2018 through 2021 of approximately US$353 million for the program, including for construction of a platform, Charlie, to provide development support at Prinos, and construction of an unmanned platform, Lamda, to develop the Epsilon field. In addition, the Group began drilling work on seven wells in the Epsilon field in the second quarter of 2017. The Group plans to fund the remaining planned expenditure through a combination of ongoing free cash flows from Prinos and from the RBL Senior Facility Agreement.

The Group's FDP for the Katakolo field was approved in September 2017 and the Group intends to make a final investment decision on the initial project phase following submission of an environmental and social impact assessment expected in 2018.

The Group's capital expenditure projections may be subject to change, for instance should the Group deliver the planned development more or less quickly or efficiently than anticipated or should it decide to defer development of certain wells. See also "*—Liquidity and Capital Resources—Capital expenditure*" for more details on projected capital expenditure with respect to the Group's developments.

See also *"Risk Factors—Risks relating to the Group's business and industry—The Group's operations require significant capital expenditure, and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain and the costs of obtaining such finance may be significant"* and *"Risk Factors—Risks relating to the Group's business and industry—The Group faces significant uncertainties in connection with its exploration, appraisal and development activities, and it may discover or produce less oil or gas than expected*".

2.8 Exploration and evaluation costs

The Group's exploration and appraisal activities involve the search for hydrocarbons resources and the determination of the technical feasibility and commercial viability of an identified resource. The success or failure of the Group's exploration and evaluation activities will affect the value and level of its reserves and resources and can result in write-offs or impairment charges.

The Group adopts the successful efforts method of accounting for exploration and evaluation costs. Once the legal right to explore has been acquired, costs directly associated with exploration and evaluation are capitalised as exploration and evaluation assets. Such costs may include initial costs of licence acquisition, seismic and other studies, and drilling. Drilling costs are capitalised until the drilling of the well is complete and the results have been evaluated. These costs include directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors.

If no potentially commercial reserves or resources are found, the exploration asset is tested for impairment. Any resulting impairment charge is passed through the profit and loss statement as other expenses. If potentially extractable hydrocarbons are found and, subject to further appraisal activity (e.g., by drilling further wells), are likely to be developed commercially, the costs continue to be carried as an oil and gas, exploration and evaluation cost while sufficient and continued progress is made in assessing the commerciality of the hydrocarbons. All such capitalised costs are subject to technical, commercial and management review as well as review for indicators of impairment at least once a year to confirm the continued intention to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off to profit or loss under other expenses in the profit and loss statement. When proved reserves are identified and development is sanctioned by management, the relevant expenditure is transferred to PPE as an oil and gas asset and is assessed for impairment and any resulting impairment loss is recognised.

The Group recorded additions to exploration and evaluation cost related intangible assets of US$5.5 million in 2016, compared to US$3.1 million in 2015 and US$1.6 million in 2014. The Group transferred US$1.2 million of exploration and evaluation cost related intangible assets to oil and gas properties in 2016. In addition, the Group recognised US$1.1 million in exploration and evaluation expenses in 2016, compared to US$0.3 million in 2015 and US$0.3 million in 2014, relating to assessing and evaluating new assets in Israel and Egypt. The Group recognised US$7.1 million in exploration and evaluation expenses in the ten months ended 31 October 2017, compared to US$1.1 million in the ten months ended 31 October 2016, relating mainly to exploration expenditure for West Kom Ombo in Egypt. For further information on the Group's exploration and evaluation activities, see *"Business Overview—Strategy"*, "*Business Overview—Overview of assets"* and *"Business Overview—Growth Opportunities"*.

2.9 Royalties and taxes

The Group's revenues and results of operations are affected by royalties, tax and other amounts payable according to applicable tax laws and the leases under which it operates. Royalties payable may also be provided for in the Group's leases or under the laws of the relevant jurisdiction. For additional information on taxes and royalties affecting the Group, as well as other applicable regulations, see *"Regulatory overview"*.

Greece

Under the Group's licence in the Prinos, Prinos North, South Kavala and Epsilon fields, royalties are payable as a percentage of gross revenue on a sliding scale, depending on the level of production. The scale references average daily production for the year, and the first 2,500 bopd attract a 0% royalty. Accordingly, no royalty was payable until the year ended 31 December 2016, when production first exceeded 2,500 bopd, reaching 3,490 bopd. A royalty is incurred on production in excess of 2,500 bopd starting at 3% of revenue, increasing to 6% of revenue for production above 5,000 bopd and to 10% of revenue for all production in excess of 10,000 bopd. The royalty of US$0.3 million in respect of the year ended 31 December 2016 reflects 3% of the gross Euro revenue of €35.3 million, adjusted for the royalty free production by an adjustment factor of 28%. Any production from the Group's Ioannina and Katakolo fields is subject to royalties on a sliding scale of 2% to 20%, and any production from the Aitoloakarnania field to royalties of 4% to 20%. In addition, the Group's Greek operations are subject to a 20% income tax and 5% regional tax. For further information on Greek tax and royalties, see *"Regulatory overview—Regulatory and legislative framework in Greece—Fiscal regulations"*.

During the year ended 31 December 2014, the Greek statutory tax audit of KOSA for the years 2006 to 2011 was finalised and the official tax report was issued by the respective tax authorities resulting in a €7.3 million (US$8.5 million) fine. This was subsequently reduced after KOSA paid €0.9 million (US$1.5 million) of stamp duties and the tax authorities wrote off €0.9 million (US$1.5 million) in interest and penalties. In addition, under the income tax corrective assessments derived from the tax report, carried-forward tax losses of KOSA were reduced from €28.9 million (US$33.6 million) to €1.4 million (US$1.6 million). The Group is awaiting a decision in the first half of 2018 on its pending appeal of the remaining €5.6 million (US$6.5 million). The appeal primarily relates to a transfer pricing-related fine of €5.3 million (US$6.2 million) relating to transactions between KOSA and EOGSA during fiscal years 2009, 2010, and 2011 which the tax authorities believe were not at arm's length and were provided at a discount. As a result, the authorities intend to impose a penalty calculated as 20% of the amounts (€15.6 million (US$18.2 million) and €11.1 million (US$12.9 million) of gross revenue, for 2010 and 2011 respectively) which they contend represent the gross income forgone by KOSA as a result of these discounts and which KOSA should have recognised as an intra-Group service fee. As required under rules regarding tax appeals, the Group has prepaid 50% of the value of the amounts for which the appeal was executed, or €2.8 million (US$3.3 million). While the Group expects to prevail in its appeal, should it not prevail it would be liable for the remaining sum. The Group also anticipates additional Greek tax liabilities and interest in respect of the unaudited years 2012 to 2016, towards which it has made provisions as described below. In addition, the five-year statute of limitation for the unaudited year of 2012 ends by the end of 2018. As of 31 October 2017, the Company had not received a tax audit request for the most recent non-prescribed unaudited year, which, in the case of Kavala Oil S.A., is 2012.

The Group has made provision towards its tax liability, recognised as US$10.9 million in the profit or loss statement in the ten month period ended 31 October 2017, of which US$2.3 million relates to additional income tax liability (see note 31 in "*Consolidated Historical Financial Information"*) and US$8.6 million to transfer pricing and income tax penalties (see note 27 in "*Consolidated Historical Financial Information"*). These provisions are reflected in the Group's statement of financial position under trade and other payables (see note 19 in *"Consolidated Historical Financial Information"*). US$4.1 million of the provisions in the profit or loss statement relate to anticipated income tax and interest in respect of unaudited years 2012 to 2016 (see note 19 in *"Consolidated Historical Financial Information"*). The Group has changed its transfer pricing policy after the tax enquiry from 2012 onwards to move to a cost-plus method which should reduce the risk of future challenges on their transfer pricing position. For additional information on the tax enquiry, see *"Additional Information—Litigation—Kavala Oil S.A. tax appeal"*.

On 12 July 2017 a tax audit order was issued by the Greek tax authorities in respect of FY2012 for Energean Oil and Gas S.A.. The tax audit commenced on 15 January 2018 and is currently in progress. For the year 2012, Energean Oil and Gas S.A, was audited by the independent auditor, Grant Thornton, in accordance with article 82 of Greek Law 2238/1994 and received unqualified tax certificates. On this basis, should any additional tax liabilities arise from the audit, they are not expected to have a material effect on the Consolidated Historical Financial Information.

The Group has also recognised deferred tax assets in respect of losses and other temporary differences to the extent that it is probable that there will be future taxable profits against which the losses and other temporary differences can be utilised. The Group has considered their carrying value at each balance sheet date and concluded that based on management's estimates, sufficient taxable profits will be generated in future years to recover such recognised deferred tax assets

At 31 October 2017 the Group had unused tax losses available to offset against future profits of US$304.1 million, compared to US$244.5 as of 31 October 2016, US$225.2 million as of 31 December 2016, US$171.3 million as of 31 December 2015 and US$107.5 million as of 31 December 2014. The Group recognised a deferred tax asset as of 31 October 2017 in respect of such losses of US$76.0 million, compared to US$61.1 million as of 31 October 2016, US$56.3 million as of 31 December 2016, US$42.8 million as of 31 December 2015 and US$26.9 million as of 31 December 2014.

Deferred tax liabilities are recognised for taxable temporary differences arising mainly on the Group's accounting and tax carrying value in Prinos oil and gas properties. These capital expenditures were expensed as incurred for tax purposes.

The recognition and carrying value of deferred tax assets can be affected by changes in the Group's estimated recoverable reserve levels which require changes in the judgments regarding the existence of deferred tax assets and in the estimates of the likely recovery of such assets.

Israel

Under the sale and purchase agreement by which the Group acquired its lease rights in the Karish and Tanin fields, the Group must pay a 7.5% royalty, plus VAT, to Delek and Avner (which have since merged together into Delek) until the date the Group will need to pay tax pursuant to the PNR Law and an 8.25% royalty, plus VAT, thereafter, in addition to the US$108.5 million in deferred payments (subject to VAT under a self-tax invoice and application of the reverse charge mechanism) provided in the contract. For additional information on the Group's acquisition of the Karish and Tanin Lease, see *"Business Overview—Overview of Assets—Israel"* and note 9 in *"Consolidated Historical Financial Information"*. In addition, the Group's Israeli operations, according to the Petroleum Law, are subject to royalties of 1/8 (12.5%) of the volume of oil produced according to the value of the gas or oil at the well head. Also according to the PNR Law the Group is subject to an oil profit tax/levy at the rate of 20% once the cost recovery ratio of the Petroleum Project has reached 150% (as calculated under the PNR Law) and the rate is gradually increased up to a ceiling rate of 46.8% when the cost recovery ratio of the Petroleum Project reaches 230%. Energean Israel is also subject to Israeli corporate income tax, currently at a rate of 23%. For further information on Israeli tax and royalties, see *"Regulatory overview—Regulatory and legislative framework in Israel—Fiscal regulations"*.

2.10 Foreign exchange

Energean's presentation currency is the U.S. dollar, primarily because oil sales prices and all of the Group's loan agreements are denominated in U.S. dollars. The U.S. dollar is the functional currency of Energean PLC, Energean Israel and Energean International. The functional currency of Energean E&P Holdings, Energean Oil & Gas SA and KOSA is the Euro. As most of the Group's staffing and certain other operating costs are denominated in Euro, the Group's results are affected by changes in the U.S. dollar/Euro exchange rate. The Group also has less significant exposures to movements in the U.S. dollar against other currencies. In particular, as the Group's operations in Israel expand as a result of the development of the Karish and Tanin fields, it expects expenditures in Israeli shekels, U.S. dollars and GBP to constitute a larger share of costs.

The Group did not engage in any foreign exchange hedging activities as of 31 October 2017.

The Group recognised an unrealised exchange profit for EOGSA in the ten month period ended 31 October 2017 of US$27.6 million, compared to a loss of US$10.0 million in the year ended 31 December 2016, US$12.1 million in 2015, US$10.2 million in 2014. Such losses related to the retranslation of U.S. dollar denominated debt, principally the EIL Intercompany Loan between Energean International and Energean Oil & Gas SA (whose functional currency is the Euro) in relation to the Third Point Shareholder Loan, as well as the EBRD facility at each period end. Realised exchange differences reflect the impact of movements in exchange rates for foreign currency transactions between the date of transaction and the date of settlement.

For further information on the Group's foreign exchange risk, see note 37.3 in "*Consolidated Historical Financial Information*".

2.11 Oil and gas reserves

The volume of the Group's commercially recoverable oil and gas reserves impacts its future potential production levels and thus potential future revenues, costs and provisions, the carrying value of its oil and gas properties, related depreciation and impairment charges, and the recognition and value of its deferred tax assets. The Group's estimates of its commercially recoverable reserves may be impacted by production volumes and by oil and gas prices to the extent that a portion of its reserves may not be economically recoverable at lower prices. A number of other factors may also impact the estimated volume of commercially recoverable reserves, including new geological information, enhanced field development, changes in drilling or production technology, and other assumptions that may affect the Group's ability in the future to recover the hydrocarbon resources at its oil and gas properties.

In 2016, the Group recorded a significant increase in 2P oil reserves. The increase in 2P recoverable oil reserves is based on multiple factors, including (i) better than predicted unswept oil volumes in the Prinos field encountered in drilling the new wells; (ii) higher than expected initial oil production rates from the new wells; (iii) the acquisition and interpretation of new seismic data on the Epsilon field; and (iv) the commitment of additional future well slots in the Prinos field development plan. The Group's oil and gas resources also increased during the period as a result of acquisitions of new Leases, particularly the Karish and Tanin fields. See *"—Acquisitions and related commitments"*.

For more information on the Group's reserves and resources, see note 4.2 in *"Consolidated Historical Financial Information"*, *"Business Overview—Summary of reserves and resources"*, *"Competent Persons' Reports"*, and *"Risk Factors— The level of the Group's crude oil and gas reserves and resources and their quality and production volumes and expected cash flows are inherently uncertain and may be lower than estimated or expected"*.

3. Current trading and prospects

For the year ended 31 December 2017, average production was 2,803 bopd (2,908 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down). This figure reflected asphaltene and drilling difficulties in the first half of 2017, which reduced production below previous projections. Production averaged 3,520 bopd in the two months ended 31 December 2017, with exit rate production at 31 December 2017 of 4,086 bopd. A significant increase in realised oil price in the last two months of the year is expected to have a positive impact on the Group's revenue and Adjusted EBITDAX in the two months ended 31 December 2017.

On 6 December 2017, Energean Israel entered into Gas Supply Agreements with Oil Refineries Ltd., Israel Chemicals Ltd., OPC Hadera Ltd., and OPC Rotem Ltd. On 7 December 2017, Energean Israel entered into Gas Supply Agreements with I.P.P. Ramat Gavriel Ltd. and I.P.P. Alon Tavor Ltd. On 21 February 2018, Energean Israel entered into a Gas Supply Agreement with Supergas Natural Ltd. See *"Business Overview—Offtake and Marketing—Gas Supply Agreements"* and *"Additional Information—Material Contracts"*.

On 8 December 2017, Energean signed an US$88.3 million lump sum turn-key EPCIC contract with GSP for construction of the Lamda platform and the drilling of three wells. See *"Additional Information—Material Contracts—GSP EPCIC Contract"*.

In 2017, Energean Israel participated in Israel's First Offshore Bid Round. Energean submitted bids for block 12 (which sits between the Karish and Tanin leases) and four additional adjacent blocks, including blocks 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and awards were announced on 12 December 2017, with Energean receiving all five of the additional licences for which it had bid. As part of the bid requirements, the Group paid US$50,000 to acquire a data package prepared for the participants of the bid which contains comprehensive information on the Levant Basin's geology, including regional 2D seismic and well data, and has provided a bid bond for each block of US$0.1 million, valid until 15 July 2018 (extendable by 120 days upon notice from the regulator). Pursuant to the bid documents and the winning announcement made on 12 December 2017, as a condition for the actual receipt of the licences, Energean provided on 11 January 2018 an additional total of US$0.5 million as a signature bonus plus a total of US$6.5 million in bank guarantees as licence bonds to secure its obligations under the licences and a total of approximately US$0.1 million as licence fees. Under the licence, the Group will be obliged to comply with the work program attached to each licence and estimates that the total capital expenditure regarding the work program for the blocks would be US$7.8 million in the first three years.

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities—a facility of up to US$105 million with EBRD and the Black Sea Trade and Development Bank ("**BSTDB**") as lenders (the "**IFI Facility**") and a US$75 million facility pursuant to which the Export-Import Bank of Romania Eximbank

SA ("**Romanian ECA**") and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders (the "**Romanian Club Facility**"). Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP EPCIC Contract. The facility is secured by substantially all of the assets of EOGSA and a guarantee from Energean E&P Holdings and a pledge of its shares in EOGSA. The facility will have a seven-year tenor. For further information on the RBL Senior Facility Agreement, including its covenants and other terms, see "*Additional Information—Material Contracts—Senior Borrowing Base Facility*".

On 2 February 2018, the Group signed an addendum to the BP Offtake Agreement, extending the agreement to the later of 1 November 2025 or delivery to BP of 25 MMbbls.

On 2 March 2018, Energean Israel entered the US$1.275 billion Senior Credit Facility underwritten by a club of Israeli and international banks for the purposes of, amongst other things, financing the development of the Karish field, paying debt service (other than principal) and paying deferred payments due from Energean Israel to Delek and Avner (the "**Delek Sellers**", now merged into Delek) pursuant to the terms of the sale and purchase agreement entered into on 16 August 2016 and made between the Delek Sellers and Energean Israel. See *"Additional Information—Material Contracts—Senior Credit Facility for the Karish-Tanin Development"*.

On 26 October 2017, 6 November 2017 and 31 January 2018, Energean Israel and TechnipFMC entered variation orders in respect of the Technip FEED Contract for a combined US$9.7 million and £0.8 million. The variation orders extended the work scope to be performed pre-FID to include all remaining FEED scope, selected detailed design elements (accelerated from the envisaged EPCIC scope) as well as FPSO model testing and (in 2018) early commencement of project management engineering services and procurement that have then been removed from the planned EPCIC scope of services.

On 2 March 2018, Energean Israel, Technip UK Limited, Technip France SA and Technip Ships One Limited (together, "**Technip**") agreed a lump-sum turnkey engineering, procurement, construction, installation and commissioning contract in respect of the development of the Karish field. See *"Additional Information—Material Contracts—Arrangements with TechnipFMC"*.

4. Description of key line items

Revenue

In the period under review, the Group generated revenue principally from the sale of oil from its Prinos and Prinos North fields under the BP Offtake Agreement. The Group also derived revenue during the period from the sale of scrap and from the sale of petroleum products, comprising products derived from the Group's petroleum production, principally sulphur, from technical services provided to third parties and from forward transactions, particularly the net gain or loss for the period from fixed price contracts and zero cost collars. Inter-segment petroleum operations and services are eliminated from Group's revenue.

Cost of sales

Cost of sales includes the cost of inventory (based on opening and closing inventories), energy cost, material consumption, staff cost and subcontracted work relating to maintenance programs and other projects not capitalised. Oil inventory is stated at the lower of cost and net realisable value. The closing inventory (in barrels) in each reporting period after the valuation at the lower of cost and net realisable value is reduced from the cost of sales of the current period and added in the cost of sales (opening inventory) in the subsequent period. Cost of sales also includes electricity, fuel, machinery repairs and maintenance, insurance, sundry expenses (such as equipment rental), consumptions (including machinery transportation costs in 2015 and 2016), royalties payable to relevant governments in respect of the Group's operations and depreciation of oil and gas assets, plant and machinery, vessel and transportation means.

Exploration and evaluation expenses

Exploration and evaluation expenses include staff costs and impairment of exploration and evaluation costs as well as third party fees.

Other income

Other income for the period included the reversal of prior period provisions related to accruals for materials and services used in processing activities, previous period energy cost credits, technical consultancy fees and the 2014 write off of a portion of Group loans due to Piraeus Bank.

Administration expenses

Administration expenses include staff costs (relating to administration, accountants, tax, human resources, other finance, part of the HSE and procurement), telecommunication and other office expenses, operating leases,

licences and taxes, repairs and maintenance, audit fees for assurance services, accounting and tax fees, legal fees, other professional fees, overseas travel, corporate social responsibility, amortisation of intangibles, depreciation of property, plant and equipment (including furniture, fixtures, equipment, software and office building) and other administration expenses such as company gifts and office supplies.

Selling and distribution expenses

Selling and distribution expenses include staff costs relating to part of the corporate and communication department payroll, advertising (including conference and sponsorship expenses and press release expenses), and sundry expenses, including travel and accommodation expenses.

Other expenses

Other expenses include other taxes (comprising stamp duty, penalties and fines), other expenses (comprising prior period expenses and other non-operating expenses), provisions for litigation expenses, other staff costs relating to previous period staff expenses relating to insurance, gain or loss from sales of property, plant and equipment, impairment loss on intangible assets, impairment loss on property, plant and equipment and impairment loss on inventory.

Finance income

Finance income includes interest income from short term bank deposits.

Finance costs

Finance costs include costs attributable to interest bearing loans and borrowings, bank overdrafts, amortisation and related party loan interest and issuance fees (as discussed in notes 30 and 33 in "*Consolidated Historical Financial Information*"), the unwinding of discount on restoration provision, interest expenses of the Group's pension benefit obligation (as described in note 20 in "*Consolidated Historical Financial Information*"), third party fees relating to consultancy services for group funding purposes, risk management and other hedging costs and other bank charges. The Group also capitalises certain borrowing costs to assets (as described in note 30 and 6 in "*Consolidated Historical Financial Information*"). Finance costs are presented net of capitalised interest costs relating to finance costs on the debt for the Prinos development.

Gain or loss from foreign exchange transactions

Gain or loss from foreign exchange transactions is the net gain or loss for the period from realised and unrealised exchange gain or loss from retranslation of foreign currency balances and transactions.

Taxation income or expense

Taxation income or expense includes corporation tax for current and prior years and deferred tax amounts.

In Cyprus, the Group is subject to corporation tax on its taxable profits at the rate of 12.5%. Any capital gains are taxed at the rate of 20%. Under certain conditions interest is subject either to corporation tax or to defence contribution. The relevant corporation tax rate for the year is 12.5% and the defence contribution rate is 30%.

In Greece, the nominal tax rates applicable to Energean are exclusively governed per each contract area by the provisions of the lease agreements ratified by Laws 2779/1999 (Prinos), 4298/2014 (Katakolo), and 4300/2014 (Ioannina). The Group's lease agreement with respect to Aitoloakarnania onshore area signed in May 2017 was ratified by the Greek parliament on 28 February 2018. The applicable tax rate according to aforementioned agreements for the period ended 31 December 2016 was 25%. The nominal tax rate of KOSA for the year 2016 was 29%, as compared to 26% for the year 2015. Tax losses, to the extent that they are accepted by the local tax authorities, can be utilised to offset taxable profits for a period of time that is dictated by the tax legislation of each country. Tax losses in relation to the Prinos exploitation area can be utilised to offset taxable profits up to the termination of Prinos exploitation area. According to Ioannina and Katakolo lease agreements the losses incurred in respect of a particular exploitation area prior to the commencement of any exploitable production shall be carried forward without any restrictions for such period. From the commencement of any exploitable production in Ioannina and Katakolo areas, and thereafter, the general income tax provisions shall apply in relation to the carrying forward of losses (currently 5 years). The Group expects that there will be sufficient profit in the following years and that deferred tax assets, recognised in the financial statements of the Group, will be recovered.

The tax on the Group's results before tax differs from the theoretical amount that would arise using the applicable tax rates as set out in note 31 to the Consolidated Historical Financial Information in "*Consolidated Historical Financial Information*".

5. Results of Operations

Consolidated statement of profit or loss

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Revenue	38,425	31,187	39,724	28,434	42,244
Cost of sales	(36,363)	(31,574)	(40,551)	(32,128)	(32,279)
Gross profit (loss)	**2,062**	**(387)**	**(827)**	**(3,694)**	**9,965**
Administration expenses	(4,339)	(3,305)	(4,134)	(4,788)	(6,241)
Selling and distribution expenses	(313)	(267)	(336)	(308)	(298)
Exploration and evaluation expenses	(7,050)	(1,116)	(1,133)	(252)	(308)
Other income	2,169	558	248	265	26,192
Other expenses	(9,770)	(1,735)	(4,688)	(3,061)	(7,482)
Operating profit (loss)	**(17,241)**	**(6,252)**	**(10,870)**	**(11,838)**	**21,828**
Finance income	14	323	327	91	166
Finance costs	(21,132)	(20,997)	(29,311)	(20,138)	(18,283)
Gain on derivative	24,109	—	—	—	—
Net foreign exchange gain/(loss)	27,621	499	(10,043)	(12,116)	(10,191)
Profit (loss) from continuing operations before tax	**13,371**	**(26,427)**	**(49,897)**	**(44,001)**	**(6,480)**
Taxation (expense) / income	(8,776)	7,066	11,517	10,581	(7,317)
Profit (loss) from continuing operations	**4,595**	**(19,361)**	**(38,380)**	**(33,420)**	**(13,797)**
Discontinued operations					
Profit/(loss) from discontinued operations	(1,403)	(108)	(229)	(66)	(104)
Profit (loss) for the period	**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**

5.1 Comparison of the ten month periods ended 31 October 2017 and 31 October 2016

	For the ten month period ended 31 October	
	2017	2016 (unaudited)
	(US$ thousands)	
Revenue	38,425	31,187
Cost of sales	(36,363)	(31,574)
Gross profit (loss)	**2,062**	**(387)**
Administration expenses	(4,339)	(3,305)
Selling and distribution expenses	(313)	(267)
Exploration and evaluation expenses	(7,050)	(1,116)
Other income	2,169	558
Other expenses	(9,770)	(1,735)
Operating profit (loss)	**(17,241)**	**(6,252)**
Finance income	14	323
Finance costs	(21,132)	(20,997)
Gain on derivative	24,109	—
Net foreign exchange gain/(loss)	27,621	499
Profit (loss) from continuing operations before tax	**13,371**	**(26,427)**
Taxation (expense)/ income	(8,776)	7,066
Profit (loss) from continuing operations	**4,595**	**(19,361)**
Discontinued operations		
Profit/(loss) from discontinued operations	(1,403)	(108)
Profit (loss) for the period	**3,192**	**(19,469)**

Revenue

Revenue increased by US$7.2 million, or 23.2%, to US$38.4 million in the ten month period ended 31 October 2017 from US$31.2 million in the ten month period ended 31 October 2016. The increase in revenue was attributable primarily to a 19.6 % increase in realised crude oil sales to US$36.6 million in the first ten months of 2017 from US$30.6 million in the same period in 2016, despite a 7.4% decline in sales volumes. This resulted principally from a 28.8% increase in realised sales price for oil during the period compared to the ten months ending 31 October 2016. In the ten month period ended 31 October 2017, the Group also recognised US$1.1 million from the rendering of technical services to Energean Israel primarily relating to the preparation of the development of Karish and Tanin assets. Revenue from the sale of petroleum products (i.e. sulphur) decreased by US$0.4 million, or 31.9%, to US$0.8 million in the ten month period ended 31 October 2017 from US$1.1 million in the ten month period ended 31 October 2016 mainly as a result of decreased sale price. In the ten month period ended 31 October 2017, the Group realised a net amount of US$0 on forward hedging transactions, compared to a net loss of US$0.5 million in 2016.

Cost of sales

Cost of oil sales increased by 13.2% in the ten month period ended 31 October 2017, to US$35.7 million compared to US$31.6 million in the ten month period ended 31 October 2016 principally due to the decreased closing balance of oil inventory in the period. Subcontracted work marginally increased by US$0.1 million, to US$0.6 million in the ten month period ended 31 October 2017 as compared to US$0.5 million in the ten month period ended 31 October 2016, reflecting shut down expenses. Depreciation decreased by US$0.8 million, or 5.1%, to US$14.5 million in the ten month period ended 31 October 2017 from US$15.3 million in the ten month period ended 31 October 2016, primarily as a result of an increase in oil and gas assets. The Group also capitalised US$2.0 million in depreciation charges in oil and gas properties in the ten month period ended 31 October 2017 as compared to US$3.1 million in the ten month period ended 31 October 2016. This decrease in capitalised depreciation was driven by an increase in the estimated useful life of the Energean Force drilling rig. Staff cost increased by US$0.7 million, or 7.4%, to US$10.6 million in the ten month period ended 31 October 2017 from US$9.9 million in the ten month period ended 31 October 2016, reflecting a reversal of a 2014 pay reduction as well overtime compensation for shut down activities . Machinery and repairs maintenance increased by US$0.4 million, or 21.5%, to US$2.2 million in the ten month period ended 31 October 2017 from US$1.8 million in 2016 due to shutdown activities. Electricity and fuel decreased in the ten month period ended 31 October 2017 to US$4.9 million from US$5.2 million in the ten month period ended 31 October 2016 due to lower electricity consumption.

Gross profit or loss

Gross profit increased to US$2.1 million in the ten month period ended 31 October 2017 from a loss of US$0.4 million in the ten month period ended 31 October 2016 reflecting an increase in realised sale price.

Exploration and evaluation expenses

Exploration and evaluation expenses increased to US$7.1 million in the ten month period ended 31 October 2017 from US$1.1 million in the ten month period ended 31 October 2016. This reflected material losses due to impairment of exploration expenditure in the West Kom Ombo asset.

Other income

Other income increased to US$2.2 million in the ten month period ended 31 October 2017 from US$0.6 million in the ten month period ended 31 October 2016, reflecting a gain from disposal of 50% of Energean Israel.

Administration expenses

Administration expenses increased by US$1.0 million, or 31.2%, to US$4.3 million in the ten month period ended 31 October 2017 from US$3.3 million in the ten month period ended 31 October 2016. This was attributable largely to an increase in staff costs due to increased headcount in finance and fees for new non-executive board members.

Selling and distribution expenses

Selling and distribution expenses remained stable, at US$0.3 million in the ten month period ended 31 October 2017.

Other expenses

Other expenses increased by US$8.0 million, to US$9.8 million, in the ten month period ended 31 October 2017 from US$1.7 million in the ten month period ended 31 October 2016. This was largely due to an increase in provisions for litigation expenses. Specifically Energean recognised US$8.6 million relating to the tax appeal of the Group's subsidiary, KOSA. See *"—Significant factors affecting the Group's results of operations—Royalties and taxes"* and *"Additional Information—Litigation—Kavala Oil S.A. tax appeal"*.

Gain on Derivative

Gain on derivative of US$24.1 million concerns a material financial asset measured at fair value at 31 October 2017, which relates to the Energean Israel B shares. As part of the reorganisation, the Group committed to acquire 50% of the class B shares of Energean Israel Limited in an Exit Event. See *"—Significant factors affecting the Group's results of operations—Accounting treatment of Energean Israel"* and note 36 in "*Consolidated Historical Financial Information"*.

Finance costs

Finance costs marginally increased by US$0.1 million, or 0.6%, to US$21.1 million in the ten month period ended 31 October 2017 from US$21.0 million in the ten month period ended 31 October 2016. This was attributable largely to a decrease in borrowing cost capitalisation. The Group capitalised US$1.1 million in borrowing costs to assets in the ten month period ended 31 October 2017, compared to US$3.9 million in the ten month period ended 31 October 2016. Finance income was US$0 million in the ten month period ended 31 October 2017, compared to US$0.3 million in the ten months ending 31 October 2016.

As a result of the above, net finance costs for the period increased by US$0.4 million, or 2.2%, to US$21.1 million in the ten month period ended 31 October 2017 from US$20.7 million in 2016.

Net foreign exchange gain/(loss)

The Group's gain from foreign exchange transactions increased by US$27.1 million, to US$27.6 million in the ten month period ended 31 October 2017, from US$0.5 million in the ten month period ended 31 October 2016. This was attributable primarily to an increase in the euro/dollar exchange rate.

Taxation income or expense

Taxation expense was US$8.8 million in the ten month period ended 31 October 2017, compared to a taxation income of US$7.1 million in the ten month period ended 31 October 2016. This was primarily due to recognition of income tax liabilities in relation to the KOSA tax appeal. The taxation expense in the period ended 31 October 2017 includes provision for income tax liabilities of US$2.5 million (of which US$2.3 million was related to the KOSA tax appeal) and US$6.3 million in deferred tax expense due principally to recognition of deferred tax in the aggregate amount of unrealised foreign exchange differences. The unrealized foreign exchange differences in the Greek entities are considered as temporary differences since these will be recognised when they become realised. In the period ended 31 October 2016 the amount of US$7.1 comprise only deferred tax income.

5.2 Comparison of the year ended 31 December 2016 with the year ended 31 December 2015

	For the year ended 31 December	
	2016	2015
	(US$ thousands)	
Revenue	39,724	28,434
Cost of sales	(40,551)	(32,128)
Gross profit (loss)	**(827)**	**(3,694)**
Administration expenses	(4,134)	(4,788)
Selling and distribution expenses	(336)	(308)
Exploration and evaluation expenses	(1,133)	(252)
Other income	248	265
Other expenses	(4,688)	(3,061)
Operating profit (loss)	**(10,870)**	**(11,838)**
Finance income	327	91
Finance costs	(29,311)	(20,138)
Net foreign exchange gain/(loss)	(10,043)	(12,116)
Loss from continuing operations before tax	**(49,897)**	**(44,001)**
Taxation (expense) / income	11,517	10,581
Loss from continuing operations	**(38,380)**	**(33,420)**
Discontinued operations		
Net results from discontinued operations	(229)	(66)
Loss for the period	**(38,609)**	**(33,486)**

Revenue

Revenue increased by US$11.3 million, or 39.7%, to US$39.7 million in the year ended 31 December 2016 from US$28.4 million in the year ended 31 December 2015. Growth in revenue was attributable primarily to a 54.5% growth in crude oil sales to US$38.8 million in 2016 from US$25.1 million in 2015, despite a 21% decrease in realised price during the period, as a result of an increase in production from the drilling of new wells in the Prinos area that came on stream in 2016 and which led to a 96.5% increase in sales volume to 1.3 MMbls in 2016, compared to 0.6 MMbbls in 2015. Revenue from the sale of petroleum products (i.e. sulphur) also increased by US$0.3 million, or 24.6%, to US$1.4 million in the year ended 31 December 2016 from US$1.1 million in the year ended 31 December 2015 mainly as a result of increased oil production following drilling of new wells in Prinos. In 2016, the Group realised a net loss of US$0.5 million on forward hedging transactions, compared to a net gain of US$2.2 million in 2015.

Cost of sales

Cost of sales increased by 26.2% in the year ended 31 December 2016, to US$40.6 million compared to US$32.1 million in the year ended 31 December 2015 principally due to an increase in depreciation charges. Inventories (oil consumption) declined by US$5.0 million in 2016, compared to an increase of US$3.1 million in 2015 due to the increased closing balance of oil inventory ultimately sold in 2017. Subcontracted work declined by US$0.1 million, or 19.4%, to US$0.7 million in the year ended 31 December 2016 as compared to US$0.8 million in the year ended 31 December 2015, reflecting the Group's continued efforts to reduce costs. Most other components of cost of sales increased in 2016. Depreciation in particular increased by US$13.9 million, or 191.0%, to US$21.2 million in 2016 from US$7.3 million in 2015, primarily as a result of increased production and an increase in estimated future capital expenditure. The Group also capitalised US$7.0 million in depreciation charges in oil and gas properties in 2016 as compared to US$2.3 million in 2015 and nil in 2014. This increase in capitalised depreciation was driven by the full-year operation of the drilling rig Energean Force, compared to four months' operations (from September to December) in 2015. Staff cost increased by US$0.8 million, or 7.1%, to US$11.6 million in 2016 from US$10.8 million in 2015, reflecting increased headcount as a result of a move away from subcontracting work as well as continued recruitment for the Energean Force. Machinery and repairs maintenance increased byUS$0.6 million, or 43.1%, to US$2.0 million in 2016 from US$1.4 million in 2015. Electricity and fuel, consumptions and sundry expenses also increase in 2016. In 2016, the Group paid US$0.3 million in royalties to the Greek state in respect of

€35.3 million in revenue from crude oil sales adjusted for royalty free production by an adjustment factor of 28%, as compared to nil in 2015, reflecting increased production above the royalty free threshold.

Exploration and evaluation expenses

Exploration and evaluation expenses increased to US$1.1 million in the year ended 31 December 2016 from US$0.3 million in the year ended 31 December 2015. This reflected an increase in staff costs included under exploration and evaluation expenses to US$1.1 million, relating to assessing and evaluating new exploration and development assets in Israel and Egypt.

Other income

Other income decreased by 6.4%, to US$0.2 million in the year ended 31 December 2016 from US$0.3 million in the year ended 31 December 2015, reflecting a decrease in the reversal of prior period provisions related to employee vacation leave and other provision, as well as previous-period energy cost credits.

Administration expenses

Administration expenses decreased by US$0.7 million, or 13.7%, to US$4.1 million in the year ended 31 December 2016 from US$4.8 million in the year ended 31 December 2015. This was attributable largely to a decrease in staff costs of US$0.8 million, or 29.7%, to US$2.0 million in 2016 from US$2.8 million in 2015. Other administrative expenses increased by US$0.3 million, or 187.8%, to US$0.4 million in 2016 from US$0.1 million in 2015. Auditors' fees for other tax services and assurance services, other professional fees, overseas travel expenses and telecommunications and other office expenses increased in 2016. Corporate social responsibility, repairs and maintenance, licences and taxes expense, amortisation of intangibles, legal fees and accounting fees declined in 2016.

Selling and distribution expenses

Selling and distribution expenses increased by 9.1%, to US$0.34 million in the year ended 31 December 2016 from US$0.31 million in the year ended 31 December 2015 as a result of increased staff and advertising costs attributable to the acquisition of new assets.

Other expenses

Other expenses increased by US$1.6 million, or 53.1%, to US$4.7 million in the year ended 31 December 2016 from US$3.1 million in the year ended 31 December 2015. This was largely due to an increase in impairment loss on property, plant and equipment to US$1.9 million in 2016, relating to machinery and equipment impairment. Impairment loss on inventory, however, decreased by US$2.1 million, or 83.8%, to US$0.4 million in 2016 from US$2.5 million in 2015, reflecting a write-down in 2015 of oil inventory to net realisable value following a drop in the oil price as compared to a write-down in 2016 of drilling maintenance materials deemed to be obsolete. The Group realised a loss of US$1.6 million from the sale of the Valiant vessel to Seven Marine in May 2016 below the vessel's net book value. Other expenses, representing prior period and other non-operating expenses and other taxes, increased by US$0.3 million, to US$0.8 million in 2016 from US$0.5 million in 2015, reflecting an impairment in other receivables.

Finance income

Finance income increased by US$0.2 million, or 259.3%, to US$0.3 million in the year ended 31 December 2016 from US$0.1 million in the year ended 31 December 2015, reflecting an increase in interest income.

Finance costs

Finance costs increased by US$9.2 million, or 45.5%, to US$29.3 million in the year ended 31 December 2016 from US$20.1 million in the year ended 31 December 2015. This was attributable largely to a 28.0% increase, to US$28.7 million, in the amortisation of related party loan interest and issuance fees in 2016 as a result of US$54.7 million in additional borrowings in May 2015. Interest bearing loans and borrowings cost also increased to US$2.4 million in 2016 as compared to nil in 2015 due to a new loan from the EBRD. Other bank charges increased to US$1.5 million in 2016 from US$0.7 million in 2015. Third party fees for Group funding purposes increased to US$0.6 million in 2016 from US$0.5 million in 2015, and costs related to unwinding of discount on

provisions increased to US$0.1 million in 2016 from US$58,000 in 2015. The Group capitalised US$4.0 million in borrowing costs to assets in 2016, up from US$3.6 million in 2015. Interest on shareholder loans was rolled into the outstanding loan balances and not cash settled in the period. Cash interest paid was US$1.3 million in 2015, compared to US$4.3 million in 2016 reflecting interest payments relating to EBRD facility loans in 2016.

As a result of the above, net finance costs for the period increased by US$9.2 million, or 45.5%, to US$29.3 million in 2016 from US$20.1 million in 2015.

Gain or loss from foreign exchange transactions

The Group's loss from foreign exchange transactions decreased by US$2.1 million, or 17.1%, to US$10.0 million in the year ended 31 December 2016, from a loss of US$12.1 million in the year ended 31 December 2015. This was attributable primarily to the decrease in the closing euro/dollar rate from 1.0887 in 2015 to 1.0541 in 2016.

Taxation income or expense

Taxation income increased by US$0.9 million, or 8.8%, to US$11.5 million in the year ended 31 December 2016 from US$10.6 million in the year ended 31 December 2015. This was due primarily to an increase in carried forward tax losses due to higher capital expenditures incurred in 2016.

5.3 Comparison of the year ended 31 December 2015 with the year ended 31 December 2014

	For the year ended 31 December	
	2015	2014
	(US$ thousands)	
Revenue	28,434	42,244
Cost of sales	(32,128)	(32,279)
Gross profit (loss)	**(3,694)**	**9,965**
Administration expenses	(4,788)	(6,241)
Selling and distribution expenses	(308)	(298)
Exploration and evaluation expenses	(252)	(308)
Other income	265	26,192
Other expenses	(3,061)	(7,482)
Operating profit (loss)	**(11,838)**	**21,828**
Finance income	91	166
Finance costs	(20,138)	(18,283)
Net foreign exchange gain/(loss)	(12,116)	(10,191)
Loss from continuing operations before tax	**(44,001)**	**(6,480)**
Taxation (expense)/ income	10,581	(7,317)
Loss from continuing operations	**(33,420)**	**(13,797)**
Discontinued operations		
Profit/(loss) from discontinued operations	(66)	(104)
Loss for the period	**(33,486)**	**(13,901)**

Revenue

Revenue decreased significantly by US$13.8 million, or 32.7%, to US$28.4 million in the year ended 31 December 2015 from US$42.2 million in the year ended 31 December 2014. The decrease was attributable primarily to a decrease in crude oil sales of US$15.1 million, or 37.5%, to US$25.1 million in 2015 as compared to US$40.3 million in 2014, as a result of a decline in oil prices in the period. Sales volumes also increased by 37.5% in 2015, from 419,755 bbls in 2014 to 577,046 bbls in 2015. Petroleum product sales increased by US$0.2 million, or 16.4%, to US$1.1 million in 2015 from US$1.0 million in 2014 due to an increase in the sulphur price. Gains on forward transactions also increased to US$2.2 million in 2015 from US$0.7 million in 2014 due to a decline in oil prices and a resulting gain on hedging instruments.

Cost of sales

Cost of sales decreased by US$0.2 million, or 0.5%, to US$32.1 million in the year ended 31 December 2015 from US$32.3 million in the year ended 31 December 2014. In 2015, cost of sales was equal to 113.0% of revenue, compared to 76.4% of revenue in 2014. This reflected a net increase in inventories of US$3.1 million in 2015 compared to a net decrease of US$7.4 million in 2014 due to a high oil inventory balance in 2014, which was sold in 2015, and consequently a high opening inventory in 2015. The decrease was also attributable in part to a decline in staff costs of US$4.1 million, or 27.3%, to US$10.8 million in 2015 from US$14.9 million in 2014, reflecting a wage cut for KWA employees (representing 247 of 259 full time employees in Kavala in 2016) introduced in 2014. Electricity and fuel costs also declined by US$3.8 million, or 39.7%, to US$5.7 million in 2015 from US$9.5 million in 2014 as a result of price decreases. Consumptions decreased by US$1.0 million, or 36.4%, to US$1.7 million in 2015 from US$2.6 million in 2014 and subcontracted work decreased by US$0.9 million, or 51.7%, to US$0.8 million. Sundry expenses and machinery repairs and maintenance also declined substantially during the period. Depreciation increased by US$0.1 million, or 1.8%, to US$7.3 million in 2015.

Exploration and evaluation expenses

Exploration and evaluation expenses remained largely steady, at US$0.3 million in the year ended 31 December 2015, compared to US$0.3 million in 31 December 2014. 2014 expenses reflected expenses related to the Ioannina and Katakolo fields and an impairment charge of US$0.2 million relating to the write-off of costs related to the East Magawish field.

Other income

Other income decreased by US$25.9 million, or 99.0%, to US$0.3 million in the year ended 31 December 2015 from US$26.2 million in the year ended 31 December 2014. The decrease reflects the 2014 write off of a portion of Group loans due to Piraeus Bank. In April 2014, the Group signed an agreement with Piraeus Bank for a discounted cash settlement of the amount of US$56.0 million for all outstanding loans of the Group as of 31 December 2013. The result of the write off was to recognise US$24.9 million as other income for the Group in 2014. The Group also recognised US$0.5 million in technical consultancy fees in 2014 relating to technical consultancy fees for the bid round in Greece.

Administration expenses

Administration expenses decreased by US$1.5 million, or 23.3%, to US$4.8 million in the year ended 31 December 2015 from US$6.2 million in the year ended 31 December 2014. The decline was largely attributable to a decrease in staff costs of US$1.2 million, or 29.5%, to US$2.8 million in 2015 from US$4.0 million in 2014 as a result of a decrease in directors remuneration by an amount $0.5 million, and a decrease in employee cost due to a 6.1% wage decrease applied in 2015 in KOSA. Other administration expenses decreased by US$0.2 million, or 52.9%, to US$0.1 million in 2015 from US$0.3 million in 2014, reflecting the impact from the implementation of the Group's cost reduction program. Licences and taxes expense increased by US$0.1 million, or 194.5%, to US$0.2 million in 2015 from US$55,000 in 2014 due to tax on a share capital increase in Kavala Oil. Depreciation of property, plant and equipment, overseas travel, telecommunications and other office expenses, operating leases, auditors' fees for other assurance services, and audit fees for statutory audit decreased during the period, while repairs and maintenance and amortisation of intangibles expense increased.

Selling and distribution expenses

Selling and distribution expenses increased by 3.4%, to US$0.3 million in the year ended 31 December 2015 from US$0.3 million in the year ended 31 December 2014. The increase was primarily attributable to an increase in staff costs to US$0.2 million in 2015 from US$0.1 million in 2014, as a result of CSR activities. Advertising expenses decreased to US$0.1 million in 2015, while sundry expenses were stable.

Other expenses

Other expenses decreased by US$4.4 million, or 59.1%, to US$3.1 million in the year ended 31 December 2015 from US$7.5 million in the year ended 31 December 2014. The decrease was attributable largely to a decrease in impairment loss on property, plant and equipment of US$4.6 million, or 99.1%, to US$40,000 in 2015 from US$4.7 million in 2014. This decline resulted largely because the 2014 figure reflected an impairment charge relating to the scrapping of the Alexander drilling rig. Other taxes expense declined by US$1.2 million, or 80.1%,

to US$0.3 million in 2015 from US$1.5 million in 2014, reflecting fines and penalties imposed by the statutory tax audit in 2014. Impairment loss on inventory increased to US$2.5 million in 2015 from US$1.0 million in 2014, due to a write-down of crude oil inventory following the drop in oil price. Other staff costs, relating to prior period insurance cost, and other expenses, comprising prior period expenses related to energy, declined in the period.

Finance income

Finance income decreased by 45.2%, to US$0.1 million in the year ended 31 December 2015 from US$0.2 million in the year ended 31 December 2014, reflecting a decline in interest income.

Finance costs

Finance costs increased by US$1.9 million, or 10.1%, to US$20.1 million in the year ended 31 December 2015 from US$18.3 million in the year ended 31 December 2014. The increase was largely attributable to an increase in amortisation of related parties loan interest and issuance fees of US$9.9 million, or 79.8%, to US$22.4 million in 2015 from US$12.5 million in 2014 as a result of increased borrowings. Third party fees for Group funding purposes declined by US$3.4 million, or 86.2%, to US$0.5 million in 2015 from US$4.0 million in 2014 due to no new financing in 2015. Bank overdrafts costs decreased to nil in 2015 from US$1.1 million in 2014 due to total settlement of all Group's overdrafts in 2014, and interest bearing loans and borrowings costs were nil in 2015, compared to US$0.8 million in 2014. Risk management costs decreased to nil in 2015 from US$0.1 million in 2014. Other bank charges increased to US$0.7 million in 2015 from US$0.6 million in 2014. Interest expenses of the Group's pension benefit obligation and costs related to the unwinding of discount on provisions decreased in 2015. In 2015, the Group capitalised US$3.6 million in borrowing costs to assets, compared to US$0.8 million in 2014.

As a result of the above, net finance costs increased by US$1.9 million, or 10.7%, to US$20.1 million in 2015 from US$18.3 million in 2014.

Gain or loss from foreign exchange transactions

The Group's loss from foreign exchange transactions increased by US$1.9 million, or 18.9%, to US$12.1 million in the year ended 31 December 2015, from a loss of US$10.2 million in the year ended 31 December 2014.

Taxation income or expense

The Group recognised taxation income of US$10.6 million in the year ended 31 December 2015, compared to a tax expense of US$7.3 million in the year ended 31 December 2014. In 2014, the statutory tax audit of KOSA assessed the retention of carried forward tax losses, which resulted in writing off the related deferred tax assets previously recognised in respect of those losses.

6. Segmental reporting

The information reported to the Group's chief executive officer and chief financial officer ("**Chief Operating Decision Makers**") for the purposes of resource allocation and assessment of segment performance is focused on five operating segments; Greece (including production asset of Prinos and non-producing exploration assets of Ioannina and Katakolo), Israel (including the 50% of Karish and Tanin assets), Egypt (including non-producing exploration asset of West Kom Ombo), Montenegro (including two non-producing exploration assets) and New Ventures. Factors considered to identify the operating segments of the Group are geographical and stage of development.

The operating results of each operating segment are regularly reviewed by the Group's Chief Operating Decision Makers in order to make decisions about the allocation of resources and to assess their performance. The Group's Chief Operating Decision Makers evaluates segmental performance on the basis of Adjusted EBITDAX, which is defined as earnings from continuing activities before income tax credit, less finance costs, finance income, gain / (loss) on derivative instruments depreciation and amortisation, excluding the effects of exceptional and other non-cash income and expenses comprising gain/(loss) on disposal, exploration and evaluation expenses, exploration costs written off, impairment of property, plant and equipment and inventory net. Adjusted EBITDAX is considered by Group management to be the most appropriate profit measure for the review of the segment operations because it excludes items which the Group does not consider to represent the operating cash

flows generated by underlying business performance. Greece segment comprises the production asset of Prinos area (including Prinos, Prinos North, South Kavala Epsilon fields) and north-east Greece (exploration assets of Ioannina and Katakolo). The Group's reportable segment under IFRS 8 Operating Segments is Greece. Segments that do not exceed the quantitative thresholds for reporting information about operating segments have been included in Other, as set out in note 5 to the "*Consolidated Historical Financial Information"*.

In the periods under review, revenue comprised sales to third parties and the eliminated intersegment sales from petroleum services. Revenue between and within segments is eliminated on consolidation. The Israel segment did not account for any revenue in the periods under review. For a breakdown of revenue and certain asset information regarding the Group's reportable segments, see note 5 in "*Consolidated Historical Financial Information*".

7. Liquidity and capital resources

7.1 Cash flows

The table below presents a summary of the Group's cash flows for the periods indicated, which have been extracted without material adjustment from the Consolidated Historical Financial Information set out in "*Consolidated Historical Financial Information*".

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Net cash from (used in) operating activities	23,440	3,881	15,235	(2,764)	17,131
Net cash (used in) investing activities	(48,655)	(55,386)	(108,844)	(49,126)	(35,683)
Net cash from financing activities	17,202	67,918	103,056	46,024	23,405
Net increase (decrease) in cash and cash equivalents	(8,013)	16,413	9,447	(5,865)	4,853
Cash and cash equivalents at end of the period	8,663	24,642	17,586	8,238	14,327

Net cash generated from operating activities

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Profit/(loss) before tax	11,968	(26,535)	(50,126)	(44,067)	(6,584)
Adjustments:					
Depreciation of property, plant and equipment	14,754	15,414	21,355	7,428	7,628
Amortisation of intangible assets	177	124	144	153	95
Share of results of joint ventures	—	—	—	66	104
Loss from the sale of property, plant and equipment	—	1,589	1,577	—	—
Impairment loss on inventory	3	—	403	2,486	1,024
Impairment loss on property, plant and equipment	111	—	1,947	39	4,560
Impairment loss on intangible assets	6,646	—	—	61	199
Gain from disposal of subsidiary	(1,540)	—			
Increase in provisions	9,754	297	738	567	175
Finance income	(14)	(323)	(327)	(91)	(166)
Finance costs	21,132	21,021	29,311	20,138	18,283
Gain from financial instruments	(24,109)	—	—	—	—
Write-off of portion of loans	—	—	—	—	(24,927)
Net foreign exchange gain/(loss)	(27,621)	(499)	10,039	12,339	12,092
	11,261	**11,089**	**15,061**	**(881)**	**12,483**
Changes in working capital					
Inventories	(192)	(4,558)	(4,952)	3,905	(5,672)
Trade and other receivables	4,593	(10,509)	(1,530)	(1,409)	18,363
Trade and other payables	7,971	7,215	6,314	(3,623)	(8,016)
Other non-current assets	(193)	644	416	(384)	264
Cash flows from (used in) operations	**23,440**	**3,881**	**15,309**	**(2,392)**	**17,422**
Tax paid	—	—	—	(28)	—
Payments in relation to provisions	—	—	(74)	(344)	(291)
Net cash from (used in) operating activities	**23,440**	**3,881**	**15,235**	**(2,764)**	**17,131**

Comparison of the ten month periods ended 31 October 2017 and 31 October 2016

Net cash generated from operating activities increased by US$19.6 million, to US$23.4 million, in the ten month period ended 31 October 2017 from US$3.9 million in the ten month period ended 31 October 2016.

This increase was primarily driven by cash flows resulting from increased crude oil sales and a decrease in trade and other receivables during the period. Crude oil sales increased by US$6.0 million, or 19.6%, as compared to the ten month period ended 31 October 2016. Trade and other receivables decreased by US$4.6 million in the ten month period ended 31 October 2017 as compared to an increase of US$10.5 million in the ten month period ended 31 October 2016.

Comparison of the year ended 31 December 2016 with the year ended 31 December 2015

Net cash generated from operating activities increased by US$18.0 million, to US$15.2 million, in the year ended 31 December 2016 from a net negative cash flow of US$2.8 million in the year ended 31 December 2015. This increase was primarily driven by cash flows resulting from increased crude oil sales and an increase in trade and other payables during the period. Crude oil sales increased by US$13.7 million, or 54.5%, and trade and other payables increased by US$6.3 million in 2016 as compared to 2015. This was partially offset by an increase of US$1.5 million in trade and other receivables and a US$5.0 million increase in inventories in 2016.

Comparison of the year ended 31 December 2015 with the year ended 31 December 2014

Net cash generated from operating activities decreased by US$19.9 million to a net negative cash flow of US$2.8 million in the year ended 31 December 2015 from a positive net cash flow of US$17.1 million in the year ended 31 December 2014. This decrease was primarily driven by a reduction in cash flows resulting from decreased crude oil sales and a decrease in trade and other payables in 2015. Crude oil sales decreased by US$15.1 million, or 37.5%, and trade and other payables decreased by US$3.6 million in 2015 as compared to 2014. Trade and other receivables also increased by US$1.4 million in 2015 as compared to 2014. This was partially offset by a US$3.9 million decrease in inventories in 2015.

Net cash used in investing activities

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Payment for purchase of intangible assets	(2,968)	(3,625)	(44,745)	(3,111)	(1,600)
Payment for purchase of property, plant and equipment	(41,045)	(52,443)	(65,935)	(46,080)	(34,249)
Disposal of subsidiary, net of cash disposed	(5,610)	—	—	—	—
Acquisition of subsidiary, net of cash acquired	—	41	47	—	—
Payment for purchase of investments in joint ventures	—	—	(41)	(26)	—
Proceeds from disposal of property, plant and equipment	—	622	1,747	—	—
Proceeds from disposal of intangible assets	954	—			
Interest received	14	19	83	91	166
Net cash used in investing activities	**(48,655)**	**(55,386)**	**(108,844)**	**(49,126)**	**(35,683)**

Comparison of the ten month periods ended 31 October 2017 and 31 October 2016

Net cash flows used in investing activities decreased by US$6.7 million, or 12.2%, to US$48.7 million in the ten month period ended 31 October 2017 from US$55.4 million in the ten month period ended 31 October 2016. This decrease reflected a reduction in drilling capital expenditure in Prinos. In addition, the decrease in intangible assets reflects a reduction of the Group's exploration activities in West Kom Ombo.

Comparison of the year ended 31 December 2016 with the year ended 31 December 2015

Net cash flows used in investing activities increased by US$59.7 million, or 121.6%, to US$108.8 million in the year ended 31 December 2016 from US$49.1 million in the year ended 31 December 2015. This reflected a US$41.6 million increase, to US$44.7 million, in payment for the purchase of intangible assets in 2016, reflecting the US$40 million acquisition of the rights in the Karish and Tanin fields in Israel, and a

US$19.9 million increase, to US$65.9 million, in payment for the purchase of property, plant and equipment, relating to drilling operations in Prinos. These increases were partially offset by an increase in proceeds from disposal of property, plant and equipment to US$1.7 million in 2016 from nil in 2015 relating to sale of the drilling supply vessel Valiant.

Comparison of the year ended 31 December 2015 with the year ended 31 December 2014

Net cash flows used in investing activities increased by US$13.4 million, or 37.7%, to US$49.1 million in the year ended 31 December 2015 from US$35.7 million in the year ended 31 December 2014. This reflects a US$1.5 million increase, to US$3.1 million, in payment for the purchase of intangible assets in 2015, relating to the West Kom Ombo seismic acquisition, and a US$11.8 million increase, to US$46.1 million, in payment for the purchase of property, plant and equipment in 2015, relating to the drilling campaign in Prinos.

Net cash from financing activities

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Repayments of loans	—	(20,000)	(20,000)	—	(75,089)
Proceeds from new loans	21,250	90,472	127,312	47,359	112,500
Finance cost paid	(3,330)	(1,088)	(2,692)	(950)	(4,241)
Transaction costs	(718)	(1,466)	(1,564)	(385)	(9,765)
Net cash from financing activities	**17,202**	**67,918**	**103,056**	**46,024**	**23,405**

Comparison of the ten month periods ended 31 October 2017 and 31 October 2016

Net cash from financing activities decreased by US$50.7 million, to US$17.2 million in the ten month period ended 31 October 2017 from US$67.9 million in the ten month period ended 31 October 2016. This decrease reflects a reduction in proceeds from new loans to US$21.3 million in the ten months ended 31 October 2017 as compared to US$90.5 million in proceeds in the ten month period ended 31 October 2016, as the Group drew US$34.2 million less in proceeds from the EBRD senior loan facility in 2017 and 2016 figures reflected the US$10 million Founder loans as well as US$20 million in short term financing from BP repaid in the same period. In 2017, the Group repaid US$0 in principal on existing loans, compared to US$20 million in 2016. As of 31 October 2017 the Group paid finance costs of US$3.3 million, compared to US$1.1 million in 2016. In the ten months ended 31 October 2017, the Group paid transaction costs of US$0.7 million, compared to US$1.5 million in the same period in 2016, reflecting the decrease in proceeds from new loans.

Comparison of the year ended 31 December 2016 with the year ended 31 December 2015

Net cash from financing increased by US$57.0 million, or 123.9%, to US$103.1 million in the year ended 31 December 2016 from US$46.0 million in the year ended 31 December 2015. This increase reflects US$127.3 million in proceeds, comprising US$62 million from the EBRD senior loan facility, a US$20 million short-term loan from BP, a US$35 million loan from Kerogen, and US$10 million from the Founders to fund the acquisition of the Karish and Tanin fields and the drilling program in Greece, as compared to US$47.4 million in proceeds from the Third Point Shareholder Loan in 2015. In 2016, the Group repaid US$20.0 million in principal on existing loans, compared to nil in 2015. In 2016, the Group paid finance costs of US$2.7 million, compared to US$1.0 million in 2015. In 2016, the Group paid transaction costs of US$1.6 million, compared to US$0.4 million in 2015, reflecting transaction costs for the new EBRD loan.

Comparison of the year ended 31 December 2015 with the year ended 31 December 2014

Net cash from financing increased by US$22.6 million, or 96.6%, to US$46.0 million in the year ended 31 December 2015 from US$23.4 million in the year ended 31 December 2014. This increase reflects US$47.4 million in proceeds from a loan from Third Point to fund the drilling program in Prinos, as compared to US$112.5 million in proceeds from Third Point in 2014. In 2015, the Group repaid nil in principal on existing loans, compared US$75.1 million in 2014. In 2015, the Group paid finance costs of US$1.0 million, compared to US$4.2 million in 2014. In 2015, the Group paid transaction costs of US$0.4 million, compared to US$9.8 million in 2014, reflecting the decrease in proceeds from new loans.

7.2 Capital resources

The Group's principal sources of liquidity have historically been borrowings from facilities extended by related parties and the Group's facilities with the EBRD and Kerogen Capital, as described below. In addition, the Group has relied on cash from its operating activities.

Following the Global Offer, the Group expects its principal source of liquidity will be the Senior Credit Facility of up to US$1.275 billion to fund the Karish and Tanin Phase 1 project and related costs, US$180 million under the RBL Senior Facility Agreement to fund its Prinos basin development, the US$20 million EBRD Subordinated Facility to fund its exploration activities, as well as cash from operations and the proceeds from the Global Offer. For additional information on the Group's capital management and liquidity risk, see notes 37.4 and 39 in *"Consolidated Historical Financial Information"*.

Cash and Restricted Cash

As of 31 October 2017, the Group held US$8.7 million in cash and cash equivalents, of which US$7.3 million was held as restricted bank deposits. Restricted cash related to guarantees held under the Group's licence agreements, for which the backing financial institutions stipulate that some or all of the amount underwritten must be restricted within cash. The Group also held restricted cash of US$0.3 million towards its environmental restoration liability for wells drilled in the Prinos field before the Group was awarded licences. As of 31 December 2016, the Group held US$0.2 million in an escrow account for the Third Point Shareholder Loan, which had been released as of 31 October 2017.

Borrowings

As of 31 October 2017, the Group had US$79.2 million in total borrowings, principally relating to the Group's outstanding facilities with the EBRD, described below.

RBL Senior Facility

In May 2016, EOGSA, as borrower, signed the EBRD Senior Facility Agreement, a five-year borrowing base facility agreement with the EBRD, subsequently amended on 12 July 2016, for a US$75 million facility to fund EOGSA's development program in the Prinos, Prinos North and Epsilon fields. On 30 January 2018, the EBRD Senior Facility Agreement was amended and restated (the "**RBL Senior Facility Agreement**"). The RBL Senior Facility Agreement comprises two facilities—the IFI Facility, a facility of up to US$105 million with EBRD and BSTDB as lenders and the Romanian Club Facility, a US$75 million facility pursuant to which the Romanian ECA and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders (EBRD, BSTDB, Romanian ECA and the commercial banks, together the "**RBL Lenders**"). Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP EPCIC Contract. The facility is secured by substantially all of the assets of EOGSA and a guarantee from Energean E&P Holdings and a pledge of its shares in EOGSA. The facility will have a seven-year tenor. For further information on the RBL Senior Facility Agreement, including its covenants and other terms, see *"Additional Information—Material Contracts—Senior Borrowing Base Facility"*.

As of 31 October 2017, the Group had drawn US$75 million of the EBRD Senior Facility Agreement.

EBRD Subordinated Facility

In July 2016, EOGSA, as borrower, signed a subordinated loan agreement (the "**EBRD Subordinated Facility Agreement**") with the EBRD, subsequently amended on 8 March 2017 and 28 February 2018, for a US$20 million facility to fund EOGSA's exploration activities. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission and an EBITDA participation amount of up to 3.5% of EBITDA (if EBITDA is positive) for the financial years 2016 and 2017 and up to 4.0% of EBITDA (if EBITDA is positive) thereafter, depending on the amount of the facility drawn. For these purposes, EOGSA's EBITDA is defined in the agreement as the total consolidated operating profit of the borrower before taking into account interest expense, taxes and extraordinary and exceptional items, and after adding back all amounts provided for depreciation and amortisation for such period, as shown in the most recent financial statements provided to the EBRD by EOGSA as set out in the agreement. The EBITDA participation amount shall accrue on a yearly basis from 1 January 2016 until 31 December 2024 and shall be payable in full on 25 August 2025. Subject to provisions regarding mandatory and voluntary prepayment, the facility is repayable in four equal instalments on 25 November 2024, 25 February 2025, 25 May 2025 and 25 August 2025. EOGSA shall pay EBRD a restructuring fee of US$0.1 million on the earlier of the first disbursement under the RBL Senior Facility Agreement and 30 days following the effective date as defined therein. The facility is secured by the second

ranking pledge and assignment as security of EOGSA's offshore and onshore bank accounts and all balances and claims arising from such accounts, certain material agreements, including the BP Offtake Agreement and KOSA services agreement, and certain insurance policies which EOGSA is required to maintain, as well as a mortgage over the Energean Force and second ranking pledges by Energean Holdings of its shares in EOGSA, by EOGSA of its shares in KOSA, and by Energean International of its interest in its intercompany loan to EOGSA dated 14 August 2014 as amended and restated on 3 April 2015. The EBRD Subordinated Facility Agreement imposes a number of affirmative and negative covenants on the Group. For further information on the EBRD Subordinated Facility Agreement covenants and other terms, see *"Additional Information—Material Contracts—EBRD Subordinated Facility Agreement"*.

As of 31 October 2017, the Group had drawn US$3.3 million of the EBRD Subordinated Facility.

Kerogen Interim Facility

Energean Israel entered an interim facility agreement dated 19 December 2016 (the "**Kerogen Interim Facility Agreement**") for a term loan of up to US$40 million to fund Energean Israel's acquisition of the Karish and Tanin leases and related costs. The initial capital was funded in the form of a US$35 million convertible loan in 2016 and a further US$5 million loan in the first quarter of 2017. In June 2017, pursuant to the EISL Subscription Agreement and the EISL Shareholders' Agreement the facility was converted, together with a further equity investment by Kerogen in Energean Israel of US$10 million, to an approximately 50% equity interest in Energean Israel. For further information, see *"Additional Information—Material Contracts—Kerogen Interim Facility Agreement*", *"Additional Information—Material Contracts—EISL Subscription Agreements"* and *"Additional Information—Material Contracts—EISL Shareholders' Agreement"*.

Third Point Shareholder Loan

In 2014, the Group received a US$125 million senior secured loan from its shareholder, Third Point, to fund the Group's ongoing drilling campaign. Proceeds were used in part to repay a US$61 million loan from VGO Alpha LP and to repay related party loans of US$11.0 million plus accrued interest. In 2015, the loan was amended to increase the amount to US$179.7 million. The loan was issued at a discount of 90% of face value, with a five year tenor repaid, fixed PIK interest rate of 9.50% until 31 December 2016 and paid fixed interest rate of 15% for the remaining tenor. On 30 June 2017, the loan was discharged in consideration for the issuance of new preference shares in Energean International (on the terms of the Reorganisation Agreement), which were acquired by the Company in consideration for the issue of the Acquisition Shares. For further information on the Reorganisation Agreement, see "*Principal Shareholders and Related Party Transactions—Related party transactions—Reorganisation in connection with Admission"*.

EIL Intercompany Loan

Pursuant to a loan agreement (the "**EIL Intercompany Loan Agreement**") between Energean International and EOGSA dated 14 August 2014, as amended 3 April 2015, 25 January 2016, and 31 March 2017, Energean International on-lent to EOGSA US$179.7 million in proceeds from the Third Point Shareholder Loan (the "**EIL Intercompany Loan**"). The agreement provided for an initial interest rate of 9.75% per annum on loans issued up to and including 31 December 2016 and 15.25% on loans issued after 1 January 2017. Pursuant to the Reorganisation Agreement, the EIL Intercompany Agreement was amended to reduce the interest rate to 5.0% per annum. The loan has a final maturity date of 31 December 2020. The majority of interest payable on the loan has been capitalised. As of 31 October 2017, carrying value of the EIL Intercompany Loan was US$208 million.

Founder Loans

In August 2016, Energean Israel entered into loan agreements with Oilco Investments, Growthy Holdings and Panos Benos for loans of US$4.75 million, US$4.75 million and US$500,000 respectively to fund the US$10 million initial payment pursuant to the sale and purchase agreement dated 16 August 2016 between Delek, Avner, and Energean Israel for the acquisition of the of the Karish and Tanin rights. Panos Benos subsequently assigned the US$500,000 loan to Adobelero Holdings, in which he holds a controlling interest. Each of the loans bears interest at 2.0% and had an initial term of 90 days. The Group fully utilised the shareholder loan facilities. The loans were discharged in June 2017, pursuant to the EISL Subscription Agreement and the EISL Shareholders' Agreement, upon the issue to the Founders of B2 shares in Energean Israel. Pursuant to the Reorganisation Agreement and the Supplementary Agreement, the Energean Israel B2 shares acquired by the Founders were acquired by the Company on 15 March 2018 in exchange for US$10 million. For further information on the Reorganisation Agreement, see "*Principal Shareholders and Related Party Transactions—Related party transactions—Reorganisation in connection with Admission"*.

7.3 Capital expenditure

The Group's total cash purchases for capital expenditure for the fiscal years 2016, 2015 and 2014 respectively was US$110.7 million, US$49.2 million and US$35.8 million. For the ten month period ended 31 October 2017, the total capital expenditure amount to US$44.0 million compared to US$56.1 million in the ten month period ended 31 October 2016. The Group's capital expenditure comprised expenditure on intangibles—principally licence acquisitions—and expenditure on property, plants and equipment, as summarised, by field, in the table below:

	Ten months ended 31 October		Year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Israel (Karish and Tanin)[1]	—	—	40,527	—	—
Egypt (West Kom Ombo)	2,184	3,026	3,605	617	234
Ioannina	784	599	613	1,971	739
Katakolo	—	—	—	523	352
Prinos	—	—	—	—	275
Payments for intangibles	**2,968**	**3,625**	**44,745**	**3,111**	**1,600**
Israel (Karish and Tanin)[1]	2,715	—	—	—	—
Prinos/Epsilon	37,894	51,934	65,426	46,080	34,249
Katakolo	436	509	509	—	—
Payments for property, plant and equipment	**41,045**	**52,443**	**65,935**	**46,080**	**34,249**
Total capital expenditure	**44,013**	**56,068**	**110,680**	**49,191**	**35,849**

Notes:

(1) In the period ended 31 October 2017 the expenditures included above in respect of the Group's Israel licences relates to capex incurred for the period 1 January until 13 June 2017 when Energean Israel became a joint venture as described in note 9 in "*Consolidated Historical Financial Information*".

Projected capital expenditure

The table below presents the Group's estimated capital expenditure by field for the period from 2018 to 2021. These estimates are subject to change.

	Estimated capital expenditure			
	2018	2019	2020	2021
		US$ thousands		
Karish and Tanin[1]	291,008	448,543	676,857	208,559
Prinos Basin fields[2]	133,100	99,000	71,400	49,000
Katakolo[3]	—	65,900	5,000	13,000
Ioannina / Aitoloakarnania[4]	5,250	4,000	500	—
West Kom Ombo[5]	—	—	—	—
Montenegro[6]	4,000	500	250	—
Israel Blocks 12, 21, 22, 23, 31[7]	6,212	1,365	169	—
Total	**439,570**	**619,308**	**754,176**	**270,559**

Notes:

(1) Estimates as contained in the NSAI Israeli CPR. Reflects 100% of expected capital expenditure, of which the Group expects to be responsible for 70%, with the remaining 30% to come from Kerogen, subject to FID by 31 March 2018 and the increase in Energean's holding in Energean Israel pursuant to the Second EISL Subscription Agreement. Absent such increase. Includes 2% assumed inflation.

(2) Estimates as contained in the NSAI Prinos CPR (2P developed and undeveloped reserves). Includes 2% assumed inflation.

(3) Management estimates. Includes 2% assumed inflation. Although the Group's FDP for Katakolo was approved in 2017, further development expenditure on the field is uncertain.

(4) Management estimates, assuming a 40% participation as per the terms of farm out agreements with Repsol. Does not include inflation.

(5) Management estimates, reflecting minimum outstanding exploration commitments. Licence expired in October 2017. Does not include inflation.
(6) Management estimates. Does not include inflation.
(7) Management estimates. Does not include inflation.

For information on the Group's capital expenditure commitments under its oil and gas leases, see *"—Commitments and contingent liabilities—Capital expenditure commitments"*, below.

8. Commitments and contingent liabilities

8.1 Contingent liabilities

The Group may face additional liabilities as a result of pending or future litigation. For a discussion of legal proceedings affecting the Group, see *"Additional Information—Litigation"* and *"Risk Factors—The Group's operations are subject to the risk of litigation, including risks relating to certain pending claims against the Group"*.

For further information on the Group's contingent liabilities, see notes 34 and 35 in *"Consolidated Historical Financial Information"*.

8.2 Operating lease commitments

The non-cancellable operating lease agreements entered by the Group relate mainly to:

- a two-year charter of the supply vessel Valiant, from November 2016 to November 2018;
- a two-year charter of the supply vessel Energean Wave, from November 2016 to November 2018;
- offices rental; and
- vehicles lease.

Total operating lease expenses amounted to US$0.3 million in 2016, US$0.3 million in 2015 and US$0.3 million in 2014. Total operating lease expenses were US$0.3 million in the ten months ended 31 October 2017, compared to US$0.2 million in the ten months ended 31 October 2016.

The future aggregate minimum lease payments under non-cancellable operating leases are as follows:

	For the ten month period ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
			US$ thousands		
Within one year	6,338	5,680	6,546	279	284
Between one and five years	686	825	5,904	567	740
After five years	86	290	219	457	660
	7,110	6,794	12,669	1,303	1,684

For further information on the Group's operating leases, see note 35.1 in *"Consolidated Historical Financial Information"*.

8.3 Capital expenditure commitments

Under the terms of its leases, the Group is subject to certain minimum investment requirements in respect of its oil and gas properties. Such requirements are typically secured by performance guarantees provided by the Group (as described under *"—Performance guarantees"*, below). The table below summarises the Group's minimum capital expenditure commitments by field, in each case under the field's current exploration or development phase as set out in the relevant lease agreement. In the event that the Group were to fail to fulfil its obligations under a lease, the commitment amount set out in the table below would be payable in respect of such lease.

	Capital expenditure commitment		
	Within one year	Between one and three years	After three years
		US$ thousands	
Prinos Basin fields[1]	—	—	—
Katakolo[2]	345	—	—
Ioannina[3]	2,571	—	—
Aitoloakarnania[4]	115	3,326	—
West Kom Ombo[5]	2,200	—	—
Karish and Tanin[6]	—	—	—
Montenegro[7]	—	3,450	—
Total	**5,231**	**6,776**	—

Notes:

(1) There are no minimum capital expenditure commitments under the terms of the Prinos lease.

(2) Minimum expenditure obligations of the second phase of the exploration stage under the terms of the proposed first amendment of the Katakolo lease, which second phase expires 2 October 2019.

(3) Minimum expenditure obligations corresponding to 40% participating interest in the remaining minimum work programme for the extended first phase of the exploration stage under the terms of the Ioannina lease, which extended first phase expires 2 October 2019.

(4) Minimum expenditure obligation corresponding the Group's 40% participating interest in the minimum work programme for the first phase of the exploration stage, now expected to expire in the third quarter of 2020, plus the Group's participating interest to the signature bonus required to be paid to HHRM on or upon the effective date.

(5) Minimum expenditure obligation to fulfil the minimum work programme of the extended second exploration phase. The Group's licence at West Kom Ombo expired in October 2017, but the Group remains subject to the letter of guarantee provided in respect of the lease. The Group is currently assessing the amounts of recoverable costs spent during the latest drilling operations so as to apply for the release of the bank guarantee.

(6) There are no minimum capital expenditure commitments under the terms of the Karish/Tanin leases.

(7) Minimum expenditure obligation corresponding to the minimum work programme of the first phase of the exploration stage, expected to expire 16 March 2020.

For information on the Group's total projected capital expenditure under its oil and gas leases, see *"—Liquidity and capital resources—Capital expenditure"*, above.

8.4 Performance guarantees

All of the Group's licences have performance guarantees attached to them, meaning that the licence specifies a minimum payment, or other amount for which the Group will be liable. Guarantees are backed by financial institutions and the terms of each agreement define the percentage of the guarantee amount to be held in restricted cash, if any. As of 31 October 2017, the Group was subject to the following performance guarantees:

- Two irrevocable bank guarantees from Energean Israel in favour of the Israeli petroleum commissioner issued by HSBC bank in the amount of US$10.0 million each, for each of the Karish and Tanin leases, to secure the Group's execution of the development plan, construction of production facilities, commencement of commercial production and compliance with the terms of the leases and relevant approvals. The guarantees replace the respective guarantees in the amount of US$7.5 million each given by the previous leaseholders, Noble, Delek, and Avner. The guarantees shall be increased to US$15.0 million each at the time of the operating permit, following completion of the construction of the production system and relevant approval from the Israeli Petroleum Commissioner. When determining the amount to be forfeited should the Group breach any of its lease obligations, the Israeli

petroleum commissioner may consider a number of factors, including, among others, the duration of any violation, the occurrence of any past violations, benefits gained by virtue of the violation and the extent of any harm to Israel's gas supply, consumers or the environment.

- A US$2.22 million letter of guarantee from EOGSA on behalf of Energean International (reduced from an initial amount of US$6.0 million) issued to Ganoub El-Wadi Holding Petroleum, the Egyptian oil commissioning authority, in respect of capital and financial commitments for the West Kom Ombo area due to expire 2 April 2018. Under the terms of the agreement with Standard Chartered, no cash is required to be restricted in respect of this guarantee. The Group is currently assessing the amounts of recoverable costs spent during the latest drilling operations so as to apply for the release of the bank guarantee.
- An annually renewable performance guarantee from EOGSA of €0.6 million granted in relation to the contract with the Greek state for exploration in Prinos. 100% of this amount is held in restricted cash as per the agreement with Eurobank S.A.
- Guarantees of €7.9 million in relation to the Ioannina licence to cover minimum expenditure obligations were formerly held by the National Bank of Greece (London branch). The guarantee was subsequently reduced to €5.6 million and, following approval of the farm-out agreement with Repsol, was replaced by a €5.6 million new bank guarantee held with HSBC. This new guarantee covers the Group's reduced interest in the field (40% participation), thus reducing the cash reserves retained as a bank security pledge to € 2.235 million.
- A €3.0 million guarantee from Energean Montenegro limited in favour of the state of Montenegro, due to expire 14 October 2020, relating to the Group's concession and mandatory work program in Montenegro. The guarantee is secured by a €3.0 million cash deposit funded by a loan from EOGSA. Energean Montenegro had previously, in May 2014, provided jointly with Mediterranean Oil & Gas Plc a first call guarantee of US$0.5 million (€0.5 million) to the government of Montenegro's Ministry of Economy for the bid related to the public invitation for submission of bids for the concession contract for the production of hydrocarbons offshore Montenegro.
- A bid guarantee of €0.1 million, 100% held as restricted cash, provided to the Greek State as part of the tender process for exploration in Western Greece, related to the (then) ongoing bid for the Aitoloakarnania block (since awarded). On 25 May 2017 the Group entered into a lease agreement for the Aitoloakarnania block and shall be asked to replace the existing €0.1 million bid guarantee with the performance minimum work programme guarantee upon ratification. The €0.1 million bid guarantee for the Arta Preveza Block expired on 30 June 2017 as this licence was not awarded to the Group. The Aitoloakarnania bid guarantee was to be replaced by a performance guarantee of €7.2 million upon receipt of notice from HHRM that this lease agreement was ratified by the Hellenic Parliament.

In addition, individual Group companies have provided a number of related party guarantees with respect to obligations of other members of the Group. As of 31 January 2018, these included:

- Energean E & P Holdings corporate guarantee in favour of EBRD securing EOGSA's liabilities under both the US$75 million Senior Facility and the US$20 million Subordinated Facility;
- Energean E & P Holdings guarantee dated 16 August 2016 pursuant to, and in accordance with, the terms of the Sale and Purchase Agreement relating to the Karish and Tanin acquisition dated 16 August 2016 between Energean Israel Limited and others and Delek Drilling Limited Partnership;
- Energean E & P Holdings guarantee dated 16 August 2016 pursuant to, and in accordance with, the terms of the Sale and Purchase Agreement relating to the Karish and Tanin acquisition dated 16 August 2016 between Energean Israel Limited and others and Avner Oil Exploration Limited Partnership;
- Energean E&P Holdings guarantee of US$20 million dated 21 December 2016 pursuant to the terms of the Cooperation Agreement dated 16 December 2016 between Energean Israel and Technip UK Limited under which Technip UK Limited has agreed to provide a counter-guarantee to HSBC (UK Branch) to secure the bank guarantees provided to the Israeli government by Energean Israel (as described above);
- Energean E&P Holdings guarantee dated 15 March 2017 pursuant to the terms of the Production Concession Contract for the Production of Hydrocarbons (the "**PCC**") for blocks 4219-26 and 4218-30 entered with the Ministry of Economy of Montenegro in favour of Energean Montenegro Limited

- Energean E & P Holdings guarantee dated 9 January 2018 to Bank Hapoalim B.M. for the issuance by the latter in favour of EISL of five letters of performance guarantee issued for the benefit of the Israel Ministry of Energy, with respect to petroleum licences for five offshore blocks 12, 21, 22, 23 and 31 (one per offshore block);
- In addition, Energean E & P Holdings expects to provide a guarantee pursuant to, and in accordance with, the terms of the Gas Sale and Purchase Agreements dated 6 December 2017 entered into between Energean Israel Limited and ORL, ICL, OPC Rotem, OPC Hadera, in relation to the guaranteed obligations defined therein. Such guarantee shall enter into force on 30 June 2021, and shall remain in force until the date on which the Gas Supply Agreement terminates in accordance with its terms.

8.5 Other commitments

Abandonment liabilities

Under its Prinos lease, abandonment and decommissioning liabilities of pre-existing offshore and onshore infrastructure are the responsibility of the Greek state. The Group is liable only for decommissioning any additional wells and any infrastructure it adds in the area, such as the Epsilon and Charlie platforms. The NSAI Prinos CPR demonstrates the abandonment liability in relation to the Prinos basin fields. Costs of US$31.6 million in the proved (1P) case and US$ 32.6 million in the proved plus probable (2P) and proved plus probable plus possible (3P) cases are included for abandonment of the platforms, wells and production facilities at the economic limit of the field. These costs are the net costs to Energean. Energean is responsible for 50% of the abandonment costs and the Greek State is responsible for the remaining 50%.

9. Off-balance sheet arrangements

Other than the items described in "—*Commitments and Contingent Liabilities*" and in the notes to the Consolidated Historical Financial Information, the Group had no off-balance sheet arrangements as of 31 October 2017.

10. Quantitative and qualitative disclosures about market risks

For a description of the Group's management of interest rate, credit, foreign exchange, and liquidity risks, see note 37 in "*Consolidated Historical Financial Information"*. For a description of the Group's inventory market price risk and customer concentration risk, see note 38 in "*Consolidated Historical Financial Information*".

11. Critical accounting estimates and judgments and recent accounting pronouncements

For a full description of the Group's critical accounting estimates and judgments and key sources of estimation uncertainty, see notes 3 and 4 of the Consolidated Historical Financial Information set out in "*Consolidated Historical Financial Information*".

PART 12
CAPITALISATION AND INDEBTEDNESS

Capitalisation and indebtedness of the Group

The table below sets out the Group's capitalisation and indebtedness as of 31 December 2017. The capitalisation and indebtedness information has been sourced from the Group's unaudited consolidated management accounts as of 31 December 2017. Investors should read this table together with Section B of Part 13 "*Consolidated Historical Financial Information*" of this document.

	As of 31 December 2017
	(US$ thousands)
Current debt	
Guaranteed[1]	—
Secured	—
Unguaranteed/unsecured	—
Total current debt	—
Non-current debt	
Guaranteed[1]	—
Secured[2]	89,605
Unguaranteed/unsecured[3]	1,345
Total non-current debt	90,950
Shareholders' equity	
Share capital	917
Merger reserve	139,903
Equity reserves[4]	63,409
Total shareholders' equity[5]	204,229
Total	295,179

Notes:

(1) The Group has no guaranteed current or non-current debt.

(2) Secured debt comprises the EBRD Senior Facility and the EBRD Subordinated Facility, with a total carrying value of US$89,605 thousand.

(3) Unguaranteed/unsecured debt comprises other loans with a carrying value of US$1,345 thousand.

(4) Equity reserves includes share premium, other reserves and translation reserves.

(5) Shareholders' equity does not include non-controlling interests and retained earnings.

The table below sets out the Group's net indebtedness as of 31 December 2017. This statement of indebtedness has been extracted without material adjustment from the Group's unaudited consolidated management accounts as of 31 December 2017.

	As of 31 December 2017
	(US$ thousands)
Cash and cash equivalents	
Cash	16
Cash equivalent	15,720
Trading securities	—
Liquidity	15,736
Current financial receivable	10,632
Current bank debt	—
Current portion of non-current debt	—
Other current financial debt	—
Current Financial Debt	—
Net Current Financial Indebtedness	(26,368)
Non-current bank loans	89,605
Bonds Issued	—
Other non-current loans	1,345
Non-current Financial Indebtedness	90,950
Net Financial Indebtedness	64,582

Notes:

(1) The Group has no current portion of non-current debt as of 31 December 2017.

(2) The Group has no other current financial debt as of 31 December 2017.

(3) Non-current bank loans comprise the non-current portion of the EBRD Senior Facility and the EBRD Subordinated Facility, with a total carrying value of US$89,605 thousand.

(4) Other non-current loans comprise the non-current portion of other loans with a carrying value of US$1,345 thousand.

On 28 February 2018 the Group submitted a request to draw down an amount of US$30 million under the RBL Senior Facility Agreement. The drawdown was effected with the conditions precedent satisfaction on 14 March 2018 and is expected to be paid to the Group on or around 20 March 2018.

Other than as described in the preceding paragraph, since 31 December 2017, there have been no material changes in the capitalisation and indebtedness of the Company.

Section A—Accountant's Report

Deloitte.

Deloitte LLP
2 New Street Square
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The Board of Directors
on behalf of Energean Oil & Gas plc
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16 March 2018

Dear Sirs/Madams

Energean Oil & Gas plc

We report on the consolidated historical financial information for the three years ended 31 December 2016 and for the ten months ended 31 October 2017 of the Group set out in Part 13 "*Consolidated Historical Financial Information*" of the prospectus dated 16 March 2018 of Energean Oil & Gas plc (the "**Company**" and together with its subsidiaries the "**Group**") (the "**Prospectus**"). This Consolidated Historical Financial Information has been prepared for inclusion in the Prospectus on the basis of the accounting policies set out in note 3 to the financial information. This report is required by Annex I item 20.1 of Commission Regulation (EC) No 809/2004 (the "**Prospectus Directive Regulation**") and is given for the purpose of complying with that requirement and for no other purpose.

We have not audited or reviewed the Consolidated Historical Financial Information for the ten months ended 31 October 2016 which has been included for comparative purposes only, and accordingly do not express an opinion thereon.

Responsibilities

The Directors of the Company are responsible for preparing the Consolidated Historical Financial Information on the basis of preparation set out in Note 2 to the Consolidated Historical Financial Information.

It is our responsibility to form an opinion on the Consolidated Historical Financial Information and to report our opinion to you.

Save for any responsibility arising under Prospectus Rule 5.5.3R(2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Annex I item 23.1 of the Prospectus Directive Regulation, consenting to its inclusion in the Prospectus.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the Consolidated Historical Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the Consolidated Historical Financial Information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Consolidated Historical Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion on Consolidated Historical Financial Information

In our opinion, the Consolidated Historical Financial Information gives, for the purposes of the Prospectus, a true and fair view of the state of affairs of the Group as of 31 October 2017, 31 December 2016, 31 December 2015 and 31 December 2014 and of its profits, cash flows and changes in equity for the financial periods then ended in accordance with the basis of preparation set out in Note 2 to the Consolidated Historical Financial Information.

Declaration

For the purposes of Prospectus Rule 5.5.3R(2)(f), we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex I item 1.2 of the Prospectus Directive Regulation.

Yours faithfully

Deloitte LLP

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Section B—Consolidated Historical Financial Information

Energean Oil & Gas PLC

Consolidated statement of financial position
(Amounts in thousands US$, unless otherwise stated)

	Notes	As at 31 October 2017	As at 31 October 2016 (unaudited)	As at 31 December 2016	As at 31 December 2015	As at 31 December 2014
ASSETS						
Non-current assets						
Property plant and equipment	6	290,318	236,367	230,180	201,009	166,304
Intangible assets	7	3,616	7,705	8,278	4,203	1,459
Investments in joint ventures		—	—	—	41	118
Other non-current asset	13	575	157	382	801	417
Deferred tax asset	18	16,761	17,789	20,678	10,751	—
Bank deposits	15	1,828	1,151	1,116	4,013	2,683
		313,098	263,169	260,634	220,818	170,981
Current assets						
Inventories	11	14,276	12,842	12,757	8,284	14,684
Trade and other receivables	12	11,716	24,915	13,739	12,162	10,753
Current tax assets	14	—	—	92	17	17
Cash and cash equivalents	15	6,835	23,491	11,861	4,225	11,644
Derivative asset	36	91,615	—	—	—	—
Assets classified as held for sale	9	—	—	45,203	—	—
		124,442	61,248	83,652	24,688	37,098
Total assets		**437,540**	**324,417**	**344,286**	**245,506**	**208,079**
EQUITY AND LIABILITIES						
Equity attributable to owners of the parent						
Share capital	16	917	14,904	14,904	14,904	14,904
Equity reserves		62,981	115,214	117,080	114,690	122,329
Merger reserves	16	139,903	—	—	—	—
Retained earnings		(145,206)	(129,268)	(148,407)	(109,799)	(65,001)
Equity attributable to equity holders of the parent		**58,595**	**850**	**(16,423)**	**19,795**	**72,232**
Non-controlling interests	10	224,294	304	303	304	(12,906)
Total Equity		**282,889**	**1,154**	**(16,120)**	**20,099**	**59,326**
Non-Current Liabilities						
Borrowings	17	79,186	268,453	255,118	187,402	117,930
Deferred tax liabilities	18	3,732	3,878	2,989	3,813	3,863
Provisions for liabilities	19, 20	6,749	3,992	4,665	3,071	3,044
Other long term liabilities	21	2,555	2,954	2,737	3,299	—
		92,222	279,277	265,509	197,585	124,837
Current Liabilities						
Trade and other payables	21	54,607	33,964	29,082	27,822	23,916
Borrowings	9, 17	—	10,022	21,130	—	—
Liabilities directly associated with assets classified as held for sale	9	—	—	44,685	—	—
Current tax liabilities	31	2,605	—	—	—	—
Provisions for liabilities	19	5,218	—	—	—	—
		62,430	43,986	94,897	27,822	23,916
Total Liabilities		**154,652**	**323,263**	**360,406**	**225,407**	**148,753**
Total Equity and Liabilities		**437,540**	**324,417**	**344,286**	**245,506**	**208,079**

Energean Oil & Gas PLC

Consolidated statement of profit or loss
(Amounts in thousands US$, unless otherwise stated)

	Notes	For the ten months ended 31 October		For the year ended 31 December		
		2017	2016 (unaudited)	2016	2015	2014
Revenue	22	38,425	31,187	39,724	28,434	42,244
Cost of Sales	23	(36,363)	(31,574)	(40,551)	(32,128)	(32,279)
Gross profit / (loss)		**2,062**	**(387)**	**(827)**	**(3,694)**	**9,965**
Administration expenses	25	(4,339)	(3,305)	(4,134)	(4,788)	(6,241)
Selling and distribution expenses	26	(313)	(267)	(336)	(308)	(298)
Exploration and evaluation expenses	24	(7,050)	(1,116)	(1,133)	(252)	(308)
Other income	28	2,169	558	248	265	26,192
Other expenses	27	(9,770)	(1,735)	(4,688)	(3,061)	(7,482)
Operating profit / (loss)		**(17,241)**	**(6,252)**	**(10,870)**	**(11,838)**	**21,828**
Finance income	30	14	323	327	91	166
Finance costs	30	(21,132)	(20,997)	(29,311)	(20,138)	(18,283)
Gain on derivative	36	24,109	—	—	—	—
Net foreign exchange gain / (loss)		27,621	499	(10,043)	(12,116)	(10,191)
Profit / (loss) from continuing operations before tax		**13,371**	**(26,427)**	**(49,897)**	**(44,001)**	**(6,480)**
Taxation (expense) / income	31	(8,776)	7,066	11,517	10,581	(7,317)
Profit / (loss) from continuing operations		**4,595**	**(19,361)**	**(38,380)**	**(33,420)**	**(13,797)**
Discontinued operations						
Profit / (loss) from discontinued operations	9	(1,403)	(108)	(229)	(66)	(104)
Profit / (loss) for the period		**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**
Attributable to:						
Owners of the parent		3,201	(19,469)	(38,608)	(33,468)	(10,270)
Non-controlling interests		(9)	—	(1)	(18)	(3,631)
		3,192	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**
Post restructuring basic and diluted earnings / (loss) per share (cents per share)						
From continuing operations		**$0.07**	**($0.27)**	**($0.54)**	**($0.47)**	**($0.14)**
From discontinued operations		**($0.02)**	**($0.00)**	**($0.00)**	**($0.00)**	**($0.00)**
Total	32	**$0.05**	**($0.27)**	**($0.54)**	**$(0.47)**	**($0.14)**

Energean Oil & Gas PLC

Consolidated statement of comprehensive income
(Amounts in thousands US$, unless otherwise stated)

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Profit / (loss) for the period	**3,192**	**(19,469)**	**(38,609)**	**(33,486)**	**(13,901)**
Other comprehensive income:					
Items that will not be reclassified subsequently to profit or loss					
Remeasurement of defined benefit pension plan	—	(130)	(148)	(9)	(242)
Exchange difference on the translation of the parent to presentation currency	—	449	(2,587)	(7,050)	(2,359)
Income taxes of items that will not be reclassified to profit or loss	—	36	41	2	63
	—	**355**	**(2,694)**	**(7,057)**	**(2,538)**
Items that may be reclassified subsequently to profit or loss					
Exchange difference on the translation of foreign operations, tax effect nil	(1,778)	169	4,347	1,316	(7,407)
	(1,778)	**169**	**4,347**	**1,316**	**(7,407)**
Other comprehensive (loss) / income after tax	**(1,778)**	**524**	**1,653**	**(5,741)**	**(9,945)**
Total comprehensive income / (loss) for the period	**1,414**	**(18,945)**	**(36,956)**	**(39,227)**	**(23,846)**
Total comprehensive income / (loss) attributable to:					
Owners of the parent	1,423	(18,945)	(36,955)	(39,531)	(19,256)
Non-controlling interests	(9)	—	(1)	304	(4,590)
	1,414	**(18,945)**	**(36,956)**	**(39,227)**	**(23,846)**

Energean Oil & Gas PLC

Consolidated statement of changes in equity
(Amounts in thousands US$, unless otherwise stated)

	Share Capital	Share Premium	Other Reserves	Translation Reserves	Retained earnings	Total	Non-controlling interests	Total
At 1 January 2014	**14,904**	**125,851**	**(40)**	**5,504**	**(54,731)**	**91,488**	**(8,316)**	**83,172**
Comprehensive loss								
Loss for the year	—	—	—	—	(10,270)	**(10,270)**	(3,631)	**(13,901)**
Exchange difference on the translation of foreign operations	—	—	—	(6,448)	—	**(6,448)**	(959)	**(7,407)**
Exchange difference on the translation of the parent to presentation currency	—	—	—	(2,359)	—	**(2,359)**	—	**(2,359)**
Remeasurement of defined benefit pension plan	—	—	(242)	—	—	**(242)**	—	**(242)**
Income taxes of other comprehensive income	—	—	63	—	—	**63**	—	**63**
Total comprehensive loss	**—**	**—**	**(179)**	**(8,807)**	**(10,270)**	**(19,256)**	**(4,590)**	**(23,846)**
At 31 December 2014	**14,904**	**125,851**	**(219)**	**(3,303)**	**(65,001)**	**72,232**	**(12,906)**	**59,326**
At 1 January 2015	**14,904**	**125,851**	**(219)**	**(3,303)**	**(65,001)**	**72,232**	**(12,906)**	**59,326**
Comprehensive loss								
Loss for the year	—	—	—		(33,468)	**(33,468)**	(18)	**(33,486)**
Exchange difference on the translation of foreign operations	—	—	—	994	—	**994**	322	**1,316**
Exchange difference on the translation of the parent to presentation currency	—	—	—	(7,050)	—	**(7,050)**	—	**(7,050)**
Remeasurement of defined benefit pension plan	—	—	(9)	—	—	**(9)**	—	**(9)**
Income taxes of other comprehensive income	**—**	**—**	**2**	**—**	**—**	**2**	**—**	**2**
Total comprehensive (loss) / income	**—**	**—**	**(7)**	**(6,056)**	**(33,468)**	**(39,531)**	**304**	**(39,227)**
Transactions with owners								
Conversion of preference shares to common shares (Note 10)	—	—	—	(1,576)	(11,330)	(12,906)	12,906	—
At 31 December 2015	**14,904**	**125,851**	**(226)**	**(10,935)**	**(109,799)**	**19,795**	**304**	**20,099**
At 1 January 2016	**14,904**	**125,851**	**(226)**	**(10,935)**	**(109,799)**	**19,795**	**304**	**20,099**
Comprehensive loss								
Loss for the year	—	—	—	—	(38,608)	(38,608)	(1)	(38,609)
Exchange difference on the translation of foreign operations	—	—	—	4,347	—	4,347	—	4,347
Exchange difference on the translation of the parent to presentation currency	—	—	—	(2,587)	—	(2,587)	—	(2,587)
Remeasurement of defined benefit pension plan	—	—	(148)	—	—	(148)	—	(148)
Income taxes of other comprehensive income	—	—	41	—	—	41	—	41
Total comprehensive (loss) / income	**—**	**—**	**(107)**	**1,760**	**(38,608)**	**(36,955)**	**(1)**	**(36,956)**
Transactions with owners								
Option for conversion to share capital (Note 9.1)	—	—	737	—	—	737	—	737
	—	—	737	—	—	737	—	737
At 31 December 2016	**14,904**	**125,851**	**404**	**(9,175)**	**(148,407)**	**(16,423)**	**303**	**(16,120)**

Energean Oil & Gas PLC

Consolidated statement of changes in equity (continued)
(Amounts in thousands US$, unless otherwise stated)

	Share Capital	Share Premium	Other Reserves	Translation Reserves	Accumulated losses	Merger reserves	Total	Non-controlling interests	Total
At 1 January 2016	**14,904**	**125,851**	**(226)**	**(10,935)**	**(109,799)**	**—**	**19,795**	**304**	**20,099**
Comprehensive loss									
Loss for the period	—	—	—	—	(19,469)	—	(19,469)	—	(19,469)
Exchange difference on the translation of foreign operations	—	—	—	169	—	—	169	—	169
Exchange difference on the translation of the parent to presentation currency	—	—	—	449	—	—	449	—	449
Remeasurement of defined benefit pension plan	—	—	(130)	—	—	—	(130)	—	(130)
Income taxes of other comprehensive income	—	—	36	—	—	—	36	—	36
Total comprehensive (loss) / income	—	—	(94)	618	(19,469)	—	(18,945)	—	(18,945)
At 31 October 2016 (unaudited)	**14,904**	**125,851**	**(320)**	**(10,317)**	**(129,268)**	**—**	**850**	**304**	**1,154**
At 1 January 2017	**14,904**	**125,851**	**404**	**(9,175)**	**(148,407)**	**—**	**(16,423)**	**303**	**(16,120)**
Profit for the period	—	—	—	—	3,201	—	3,201	(9)	3,192
Exchange difference on the translation of foreign operations	—	—	—	(1,778)	—	—	(1,778)	—	(1,778)
Exchange difference on the translation of the parent to presentation currency	—	—	—	—	—	—	—	—	—
Total comprehensive income	—	—	—	(1,778)	3,201	—	1,423	(9)	1,414
Transactions with owners of the company									
Issuance of shares	65	—	—	—	—	—	65	—	65
Group restructuring	(14,052)	(125,851)	—	—	—	139,903	—	—	—
Modification of derivative (Note 36.2)	—	—	67,506	—	—	—	67,506	—	67,506
Transaction with non-controlling interests (Note 10)	—	—	6,761	—	—	—	6,761	224,000	230,761
Transfer due to disposal of subsidiary (Note 9.1)	—	—	(737)	—	—	—	(737)	—	(737)
At 31 October 2017	**917**	**—**	**73,934**	**(10,953)**	**(145,206)**	**139,903**	**58,595**	**224,294**	**282,889**

Energean Oil & Gas PLC
Consolidated statement of cash flows

(Amounts in thousands US$, unless otherwise stated)

	Notes	For the ten months ended 31 October		For the year ended 31 December		
		2017	2016 (unaudited)	2016	2015	2014
Operating activities						
Profit / (loss) before tax		11,968	(26,535)	(50,126)	(44,067)	(6,584)
Adjustments:						
Depreciation of property, plant and equipment	6	14,754	15,414	21,355	7,428	7,628
Amortisation of intangible assets	7	177	125	144	153	95
Share of results of joint ventures		—	—	—	66	104
Loss from the sale of property, plant and equipment		—	1,589	1,577	—	—
Impairment loss on inventory		3	—	403	2,486	1,024
Impairment loss on property, plant and equipment	6	111	—	1,947	39	4,560
Impairment loss on intangible assets	7	6,646	—	—	61	199
Gain from disposal of subsidiary	28	(1,540)	—	—	—	—
Increase in provisions		9,754	297	738	567	175
Finance income	30	(14)	(323)	(327)	(91)	(166)
Finance costs	30	21,132	21,021	29,311	20,138	18,283
Gain from financial instruments	28	(24,109)	—	—	—	—
Write-off of portion of loans	28	—	—	—	—	(24,927)
Net foreign exchange (loss)/gain		(27,621)	(499)	10,039	12,339	12,092
		11,261	11,089	15,061	(881)	12,483
Changes in working capital:						
Inventories		(192)	(4,558)	(4,952)	3,905	(5,672)
Trade and other receivables		4,593	(10,509)	(1,530)	(1,409)	18,363
Trade and other payables		7,971	7,215	6,314	(3,623)	(8,016)
Other non-current asset		(193)	644	416	(384)	264
Cash flows from / (used in) operations		**23,440**	**3,881**	**15,309**	**(2,392)**	**17,422**
Tax paid		—	—	—	(28)	—
Payments in relation to provisions		—	—	(74)	(344)	(291)
Net cash from / (used in) operating activities		**23,440**	**3,881**	**15,235**	**(2,764)**	**17,131**
Investing activities						
Payment for purchase of intangible assets	7	(2,968)	(3,625)	(44,745)	(3,111)	(1,600)
Payment for purchase of property, plant and equipment	6	(41,045)	(52,443)	(65,935)	(46,080)	(34,249)
Disposal of subsidiary, net of cash disposed		(5,610)	—	—	—	—
Acquisition of subsidiary, net of cash acquired	9	—	41	47	—	—
Payment for purchase of investments in joint ventures	9	—	—	(41)	(26)	—
Proceeds from disposal of property, plant and equipment	6	—	622	1,747	—	—
Proceeds from disposal of intangible assets	7	954	—	—	—	—
Interest received		14	19	83	91	166
Net cash used in investing activities		**(48,655)**	**(55,386)**	**(108,844)**	**(49,126)**	**(35,683)**

Energean Oil & Gas PLC
Consolidated statement of cash flows

(Amounts in thousands US$, unless otherwise stated)

	Notes	For the ten months ended 31 October 2017	For the ten months ended 31 October 2016 (unaudited)	For the year ended 31 December 2016	For the year ended 31 December 2015	For the year ended 31 December 2014
Financing activities						
Repayments of loans	17	—	(20,000)	(20,000)	—	(75,089)
Proceeds from new loans	17, 9	21,250	90,472	127,312	47,359	112,500
Finance cost paid		(3,330)	(1,088)	(2,692)	(950)	(4,241)
Transaction costs		(718)	(1,466)	(1,564)	(385)	(9,765)
Net cash from financing activities		**17,202**	**67,918**	**103,056**	**46,024**	**23,405**
Net increase / (decrease) in cash and cash equivalents		(8,013)	16,413	9,447	(5,865)	4,853
Cash and cash equivalents:						
At beginning of the year		17,586	8,238	8,238	14,327	11,286
Effect of exchange rate fluctuations on cash and cash equivalents		(910)	(9)	(99)	(224)	(1,812)
At end of the period	15, 9	**8,663**	**24,642**	**17,586**	**8,238**	**14,327**
Current cash and cash equivalents		6,835	23,491	11,861	4,225	11,644
Non-current bank deposits		1,828	1,151	1,116	4,013	2,683
Current cash and cash equivalents held for sale		—	—	4,609	—	—
Cash and cash equivalents at end of the period		**8,663**	**24,642**	**17,586**	**8,238**	**14,327**

Supplemental cash flow information:

	Note	For the ten months ended 31 October 2017	For the ten months ended 31 October 2016	For the year ended 31 December 2016	For the year ended 31 December 2015	For the year ended 31 December 2014
Non-Cash Investing and Financing Activities						
Settlement of loan for issuance of preference shares	10, 17	230,564	—	—	—	—
Capitalisation of depreciation to oil & gas properties	6	1,974	3,050	7,014	2,339	—
Capitalised borrowing costs		1,056	3,855	3,992	3,553	834

1. Incorporation and principal activities

1.1 Incorporation

Energean Oil & Gas PLC (the 'Company') was incorporated in United Kingdom on 8 May 2017 as a public company with limited liability, under the Companies Act 2006. On incorporation, the Company issued 50,000 ordinary shares of a nominal value of £1.00 per share. Its registered office is at 21 Gloucester Place, London W1U 8HR, United Kingdom. The Company and all subsidiaries controlled by the Company, are together referred to as "the Group".

On 30 June 2017, the Company reorganised the business and became the parent company of the Group through the acquisition of the full share capital of Energean E&P Holdings Limited in exchange for 65,643,120 £0.01 shares in the Company (the "transaction"). This transaction, which resulted in Energean E&P Holdings Limited becoming a wholly-owned subsidiary of the Company and the Company becoming the new immediate holding company of Energean E&P Holdings Limited, constitutes a group reconstruction and a transaction between entities under common control. This transaction falls outside the scope of IFRS 3 'Business Combinations.' There is no other authoritative guidance for such situations under IFRS. In the absence of such authoritative guidance under IFRS, the transaction has been accounted for in these consolidated historical financial information using the principles of merger accounting under Financial Reporting Standard 102, the Financial Reporting Standard applicable in the UK and the Republic of Ireland, which results in the net assets of Energean E&P Holdings Limited being recorded at carrying value and presented as if the Company and Energean E&P Holdings Limited had always been part of the same consolidated group. This policy, which does not conflict with International Financial Reporting Standards (IFRS), reflects the economic substance of the transaction. The effect of this transaction is reflected in the share capital of the Group on the date it became effective.

1.2 Principal activities

The Group has been established with the objective of exploration, production and commercialisation of crude oil and natural gas in Greece, Israel, North Africa and the wider Eastern Mediterranean. The Group's core assets as of 31 October 2017 are comprised of:

	Asset	Country	Group's working interest	Partner's working interest	Field Phase
1.	Karish[1]	Israel	50%	50%	Development
2.	Tanin[1]	Israel	50%	50%	Development
3.	Prinos	Greece	100%	N/A	Production
4.	Prinos North	Greece	100%	N/A	Production / undeveloped
5.	South Kavala	Greece	100%	N/A	Production
6.	Epsilon	Greece	100%	N/A	Undeveloped
7.	Prinos exploration area	Greece	100%	N/A	Exploration
9.	Kataloko	Greece	100%	N/A	Undeveloped
10.	Ioannina[2]	Greece	40%	60%	Exploration
11.	Aitolokarnania[3]	Greece	40%	60%	Exploration
12.	West Kom Ombo	Egypt	60%	40% (Pan Pacific Petroleum)	Exploration
13.	Block 26	Montenegro	100%	N/A	Exploration
14.	Block 30	Montenegro	100%	N/A	Exploration

1 In Energean Israel, the company of the Group that holds 50% interests in Karish and Tanin licences, Kerogen Capital hold the remaining 50% (Note 9). At 31 October 2017 Energean Israel is an associate in which the Group has 0% economic interest.

2 In March 2017 the Group agreed to farm out a 60% working interest to Repsol (operator) in Ioannina block.

3 Subject to ratification of lease agreement by Greek Parliament

The principal operations of the Group are in Greece, Egypt and Israel.

2. Basis of preparation

The consolidated historical financial information have been prepared on the historical cost basis, except for the revaluation of certain financial instruments that are measured at revalued amounts or fair values at the end of each reporting period, as explained in the accounting policies below.

The consolidated historical financial information has been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU), except for the application of International Accounting Standards (IAS) 8 'Accounting Policies, Changes in Accounting Estimates and Errors'. Preparation in accordance with IFRS requires compliance with IAS 8, which requires certain disclosures around the correction of prior period errors and changes in accounting policies. The consolidated historical financial information does not include such disclosures under IAS 8. This preparation is not in accordance with the requirements of IFRS, but is commonly used for the preparation of historical financial information prepared for inclusion in investment circulars in accordance with the requirements of the Prospectus Directive regulations and UK Listing Rules, and subject to the application of Standards of Investment Reporting (SIR) 2000. In all other respects, the consolidated historical financial information has been prepared in accordance with IFRS as adopted by the EU. The interim consolidated historical information as of and for the ten month period ended 31 October 2017 and 2016 have been prepared in accordance with the International Accounting Standard (IAS) 34 'Interim Financial Reporting' as adopted by the EU except for the application of IAS 8 as outlined above.

The consolidated historical financial information is presented in U.S. Dollars and all values are rounded to the nearest thousand dollars except where otherwise indicated.

Going Concern

The Directors have exercised significant judgement in assessing that the preparation of the consolidated historical financial information on a going concern basis is appropriate. In making this assessment, the important factors considered, among others, include the current financial position and the profitability of the Group as well their expectations in relation to future business prospects, and future profitability and cash flows of the Group. Another important factor for determining that the going concern basis remains appropriate is the ability of raising necessary funding as and when needed. Subsequent to the balance sheet date, the Group's liquidity position has been significantly improved by the amendment of the Group's existing EBRD Senior Facility agreement signed on 30 January 2018, increasing available funds to US$180 million and the addition of a US$1.275 billion Senior Credit Facility agreement, effective upon the Group's admission to trading on the London Stock Exchange. Accordingly, the Directors have a reasonable expectation that the Group have adequate resources to continue in operational existence for the foreseeable future, and consider it appropriate to adopt the going concern basis in preparing the historical financial information.

3. Accounting policies

The principal accounting policies and measurement bases used in the preparation of the consolidated historical financial information are set out below. These policies have been consistently applied to all periods presented in the consolidated historical financial information unless otherwise stated.

3.1 Basis of consolidation

The consolidated historical financial information incorporates the financial statements of the Company and entities controlled by the Company (its subsidiaries) as detailed in Note 8. Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee
- Exposure, or rights, to variable returns from its involvement with the investee, and
- The ability to use its power over the investee to affect its returns

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

The results of subsidiaries acquired or disposed of during the year are included in the consolidated historical financial information from the effective date of acquisition or up to the effective date of disposal, as appropriate.

Profit or loss and each component of Other Comprehensive Income (OCI) are attributed to owners of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the Group. All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Group's equity therein. Non-controlling interests consist of the amount of those interests at the date of the original business combination and the non-controlling interests' share of changes in equity since the date of the combination.

Transactions with non-controlling interests that do not result in loss of control of a subsidiary, are accounted for as transactions with the owners (i.e. as equity transactions). The difference between the fair value of any consideration and the resulting change in the non-controlling interests' share of the net assets of the subsidiary, is recorded in equity.

3.2 Functional and presentation currency and foreign currency translation

- **Functional and presentation currency**

  Items included in the consolidated historical financial information of the Company and its subsidiaries entities are measured using the currency of the primary economic environment in which each entity operates ("the functional currency").

  The functional currency of the Company is U.S. Dollars (US$). The U.S. Dollar is the currency that mainly influences sales prices, revenue estimates and also highly affect its operations. The functional currencies of the Group's main subsidiaries are analysed as follows: for Energean E&P Holdings Ltd, Energean Oil & Gas S.A., Kavala Oil SA and Energean Montenegro is Euro, for Energean International Limited and Energean Israel Limited is US$.

- **Transactions and balances**

  Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from monetary assets and liabilities denominated in foreign currencies are recognised in the profit or loss. Such monetary assets and liabilities are translated at year end foreign exchange rates. Non-monetary items denominated in a foreign currency are translated at the exchange rates prevailing at the date of the transaction and are not subsequently remeasured.

- **Translation to presentation currency**

  For the purpose of presenting consolidated historical financial information, the assets and liabilities of the Group are expressed in US$. The Company and its subsidiaries assets and liabilities are translated using exchange rates prevailing on the reporting date. Income and expense items are translated at the average exchange rates for the period, unless exchange rates fluctuated significantly during that period, in which case the exchange rates at the dates of the transactions are used. Exchange differences arising are recognised in other comprehensive income and accumulated in the Group's translation reserve. Such translation differences are reclassified to profit or loss in the period in which the foreign operation is disposed of.

3.3 Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration transferred in a business combination is measured at fair value, which is calculated as the sum of the acquisition-date fair values of the assets transferred by the Group, liabilities incurred by the Group to the former owners of the acquiree and the equity interests issued by the Group in exchange for control of the acquiree. For each business combination the acquirer measures the non-controlling interest in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are recognised in the consolidated statement of profit or loss as incurred.

Where appropriate, the cost of acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified are accounted for in profit or loss. Contingent consideration classified as equity is not remeasured.

The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 *Business Combinations* (revised 2008) are recognised at their fair value at the acquisition date, except that:

- deferred tax assets or liabilities, and assets or liabilities related to employee benefit arrangements are recognised and measured in accordance with IAS 12, '*Income Taxes*' and IAS 19, '*Employee Benefits*' respectively;
- liabilities or equity instruments related to share-based payment arrangements of the acquire or share-based payment arrangements of the Group entered into to replace share-based payment arrangements of the acquire are measured in accordance with IFRS 2 *Share-Based Payment* at the acquisition date; and
- non-current assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 '*Non-current Assets Held for Sale and Discontinued Operations*', which are measured at fair value less costs to sell.

If the initial accounting for a business combination is incomplete by the end of the reporting year in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as at the acquisition date that, if known, would have affected the amounts recognised as at that date.

The measurement period is the year from the date of acquisition to the date the Group receives complete information about facts and circumstances that existed as at the acquisition date and is subject to a maximum of one year.

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. If, after reassessment, the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a bargain purchase gain.

3.4 Investments in joint ventures

A joint arrangement is one in which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

- **Joint Operations**

A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have the right to the assets and obligations for the liabilities, relating to the arrangement. In relation to its interests in joint operations, the Group recognises its share of:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Share of the revenue from the sale of the output by the joint operation
- Expenses, including its share of any expenses incurred jointly

- **Joint Venture**

A joint venture is an arrangement (which usually involves the establishment of separate entity) that the Group controls jointly with one or more other investors, and over which the Group has rights to a share of the arrangement's net assets rather than direct rights to underlying assets and obligations for underlying liabilities.

The investments in joint ventures are initially recognised at cost and are accounted for by the equity method of accounting. Under the equity method, the investments in joint ventures are carried in the consolidated statement of financial position at cost. The carrying amount of the investment is adjusted to recognise changes in the Group's share of the net assets of a joint venture since the acquisition date less any impairment in the value of individual investments. The Group's share of post-acquisition profits or losses of a joint venture is recognised in profit or loss. The aggregate of the Group's share of profit or loss of the joint venture is shown on the face of the consolidated statement of profit and loss and represents profit or loss after tax and non-controlling interest in the subsidiaries of the joint venture. Unrealised gains and losses on transactions between the Group and a joint venture are eliminated to the extent of the Group's interest in the joint venture.

Any excess of the cost of acquisition over the Group's share of the net fair value of the identifiable assets, liabilities and contingent liabilities of a joint venture at the date of acquisition is recognised as goodwill. The goodwill is included within the carrying amount of the investment and is assessed for impairment as part of the investment. Any excess of the Group's share of the net fair value of the identifiable assets, liabilities and contingent liabilities over the cost of acquisition is recognised immediately in profit or loss.

When the Group's share of losses in a joint venture equals or exceeds its interest in the joint venture, the Group does not recognise further losses, unless the Group has incurred obligations or made payments on behalf of the joint venture.

At each reporting date, the Group determines whether there is objective evidence that the investment in the joint venture is impaired. If there is such evidence, the Group determines the amount of impairment as the difference between the recoverable amount of the joint venture and its carrying value, and then recognises the loss in the consolidated statement of profit or loss.

The accounting policies of a joint venture are aligned with those adopted by the Group where necessary to ensure consistency.

3.5 Property, plant and equipment

Property, plant and equipment is comprised of oil and gas properties, machinery, furniture and fixtures and vessel costs.

Initial recognition

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Depreciation

Depreciation of property, plant and equipment related to hydrocarbon production activities generally are depreciated on a unit-of-production basis over the proved and probable developed and undeveloped commercial reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. For the purposes of calculating depreciation, the value of oil and gas properties includes both historical capital expenditure and estimated future capital expenditure related to the development of undeveloped 2P reserves. Depreciation of other property, plant and equipment is calculated on the straight-line method so as to write-off the cost amount of each asset to its residual value, over its estimated useful life. The useful life of each class is estimated as follows:

	Years
Buildings	12
Vessel cost	5 - 14
Plant and machinery	7 - 30
Furniture, fixtures and equipment	7

Depreciation of the assets in the course of construction commences when the assets are ready for their intended use, on the same basis as other assets of the same class.

An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement of profit or loss when the asset is derecognised.

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date.

Development Costs

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells is capitalised within oil and gas properties in property, plant, and equipment on the consolidated statement of financial position.

Repairs, maintenance, and renovations

Expenditure for routine repairs and maintenance of property, plant and equipment is charged to the profit or loss in the year in which it is incurred. The cost of major improvements and renovations and other subsequent expenditure are included in the carrying amount of the asset when the recognition criteria of IAS 16 '*Property, Plant and Equipment*' are met. Major improvements and renovations capitalised are depreciated over the remaining useful life of the related asset.

3.6 Intangible assets

- **Computer software**

Costs that are directly associated with identifiable and unique computer software products controlled by the Group and that will probably generate economic benefits exceeding costs beyond one year are recognised as intangible assets. Subsequently computer software is carried at cost less any accumulated amortisation and any accumulated impairment losses.

Costs associated with maintenance of computer software programmes are recognised as an expense when incurred.

Computer software costs are amortised using the straight-line method over their useful live, which commences when the computer software is available for use. Their amortisation expense is included in administration expenses.

- **Exploration and evaluation costs**

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. Exploration and evaluation assets are accounted for using the successful efforts method of accounting.

Once the legal right to explore has been acquired, costs directly associated with exploration and evaluation are capitalised as exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated. These costs include licence acquisition costs, directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors and suppliers.

If no potentially commercial reserves are found, the exploration asset is tested for impairment. If potentially extractable hydrocarbons are found and, subject to further appraisal activity (e.g., by drilling further wells), have the potential to be developed commercially, the costs continue to be carried as exploration & evaluation cost while sufficient and continued progress is made in assessing the commerciality of the hydrocarbons. All such capitalised costs are subject to technical, commercial and management review as well as review for indicators of impairment at least once a year to confirm the continued intention to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off to profit or loss.

When proved reserves of oil are identified and development is sanctioned by management, the relevant expenditure is assessed for impairment and any resulting impairment loss is recognised before reclassifying the balance to oil and gas properties within property, plant and equipment.

3.7 Impairment of non-financial assets

At each reporting date, the Group reviews the carrying amounts of its depreciable property, plant and equipment and intangible assets to determine whether there is any indication that those assets have suffered an impairment loss. Impairment is assessed at the level of cash-generating units (CGUs) which, in accordance with IAS 36 '*Impairment of Assets*', are identified as the smallest identifiable group of assets that generates cash inflows, which are largely independent of the cash inflows from other assets. This is usually at the individual royalty, stream, oil and gas or working interest level for each property from which cash inflows are generated.

An impairment loss is recognised for the amount by which the asset's carrying value exceeds its recoverable amount, which is the higher of fair value less costs of disposal (FVLCD) and value-in-use (VIU). The future cash flow expected is derived using estimates of proven and probable reserves, a portion of resources that is expected to be converted into reserves and information regarding the mineral, stream and oil & gas properties, respectively, that could affect the future recoverability of the Company's interests. Discount factors are determined individually for each asset and reflect their respective risk profiles.

Assets are subsequently reassessed for indications that an impairment loss previously recognised may no longer exist. An impairment charge is reversed if the conditions that gave rise to the recognition of an impairment loss are subsequently reversed and the asset's recoverable amount exceeds its carrying amount. Impairment losses can be reversed only to the extent that the recoverable amount does not exceed the carrying value that would have been determined had no impairment been recognised previously.

Exploration and evaluation assets are tested for impairment when there is an indication that a particular exploration and evaluation project may be impaired. Examples of indicators of impairment include a significant price decline over an extended period, the decision to delay or no longer pursue the exploration and evaluation project, or an expiration of rights to explore an area. In addition, exploration and evaluation assets are assessed for impairment upon their reclassification to producing assets (oil and gas interest in property, plant and equipment). In assessing the impairment of exploration and evaluation assets, the carrying value of the asset would be compared to the estimated recoverable amount and any impairment loss is recognised immediately in profit or loss.

3.8 Leasing

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. Leases where a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases.

- **Operating leases**

The Group as lessee:

Rentals payable under operating leases are charged to profit or loss on a straight-line basis over the term of the relevant lease. Benefits received and receivable as an incentive to enter into an operating lease as well as prepayments and any other premiums paid are spread on a straight-line basis over the lease term.

3.9 Financial instruments

Financial assets and financial liabilities are recognised when the Group becomes a party to the contractual provisions of the instrument.

Financial instruments are initially measured at fair value, plus transaction costs that are directly attributable to the acquisition of financial assets or the issuance of financial liabilities that are recorded at other than fair value through profit and loss. Financial assets are classified into the following specified categories: financial instruments "at fair value through profit and loss" (FVTPL); "held to maturity investments"; "available for sale (AFS) financial assets" and "loans and receivables". Financial liabilities are classified as FVTPL and other liabilities. The classification of financial instruments depends on the nature and purpose of the financial assets and is determined at the time of initial recognition. For the periods presented the Group' financial assets consist of "loans and receivables" and FVTPL and financial liabilities consist of FVTPL and other liabilities.

Financial instruments at fair value through profit or loss

FVTPL include financial instruments held for trading (HFT) and financial instruments designated upon initial recognition at fair value through profit or loss. Financial instruments are classified as HFT if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives are also classified as HFT. The Group has not designated any financial instruments at fair value through profit or loss. Financial instruments at fair value through profit or loss are carried in the consolidated statement of financial position at fair value with net changes in fair value presented as gain or loss in the consolidated statement of profit or loss. The Group's financial instrument that have been classified as HFT are derivative instruments.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not HFT or designated at fair value though profit or loss.

Loans and receivables

Loans and receivables that have fixed or determinable payments and are not quoted in an active market are classified as loans and receivables. Loans and receivables are measured at initial recognition at fair value plus any directly attributable transaction costs, and are subsequently measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate, except for short-term receivables when the recognition of interest would be immaterial in the consolidated statement of profit and loss. The Group's loans and receivables consist of other non-current assets, cash and cash equivalents, trade and other receivables.

Impairment of financial assets

The Group assesses, at each reporting date, whether there is objective evidence that a financial asset or a group of financial assets is impaired. An impairment exists if one or more events that has occurred since the initial

recognition of the asset (an incurred 'loss event'), has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganisation and observable data indicating that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Group first assesses whether impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be, recognised are not included in a collective assessment of impairment.

The amount of any impairment loss identified is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not yet been incurred). The present value of the estimated future cash flows is discounted at the financial asset's original effective interest rate.

The carrying amount of the asset is reduced through the use of an allowance account and the loss is recognised in statement of profit or loss. Interest income (recorded as finance income in the statement of profit or loss) continues to be accrued on the reduced carrying amount and is accrued using the rate of interest used to discount the future cash flows for the purpose of measuring the impairment loss. Loans together with the associated allowance are written off when there is no realistic prospect of future recovery and all collateral has been realised or has been transferred to the Group. If, in a subsequent year, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognised, the previously recognised impairment loss is increased or reduced by adjusting the allowance account. If a write-off is later recovered, the recovery is credited consistent with where the impairment was recorded in the statement of profit or loss.

- **Financial liabilities**

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, and other financial liabilities, which include borrowings and trade and other payables. The Group does not have any financial liabilities classified as fair value through profit or loss except derivative instruments.

Other Liabilities:

Other financial liabilities are recognised initially at fair value, net of directly attributable transaction costs and are subsequently measured at amortised cost using the effective interest method.

The effective interest rate method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that discounts the expected cash flows over the estimated life of the instrument to its net carrying amount. The effective interest rate amortisation is included as finance costs in the consolidated statement of profit or loss.

Derecognition of Financial Liabilities

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or it expires.

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a

derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

- **Equity instruments**

Equity instruments issued by the Group are recorded at the proceeds received, net of direct issue costs.

Ordinary shares

Ordinary shares are classified as equity and measured at their nominal value. Any premiums received on issue of share capital above its nominal value, are recognised as share premium within equity. Associated issue costs are deducted from share premium.

- **Compound instruments**

The component parts of compound instruments (convertible notes) issued by the Group are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangements and the definitions of a financial liability and an equity instrument. Conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a fixed number of the Group's own equity instruments is an equity instrument.

At the date of issue, the fair value of the liability component is estimated using the prevailing market interest rate for similar non-convertible instruments. This amount is recorded as a liability at fair value and measured at amortised cost using the effective interest method until extinguished upon conversion or at the instrument's maturity date.

The conversion option classified as equity is determined by deducting the amount of the liability component from the fair value of the compound instrument as a whole. This is recognised and included in equity, net of income tax effects, and is not subsequently remeasured. In addition, the conversion option classified as equity will remain in equity until the conversion option is exercised, in which case, the balance recognised in equity will be transferred to share premium. When the conversion option remains unexercised at the maturity date of the convertible note, the balance recognised in equity will be transferred to other equity reserves. No gain or loss is recognised in profit or loss upon conversion or expiration of the conversion option.

Transaction costs that relate to the issue of the convertible notes are allocated to the liability and equity components in proportion to the allocation of the gross proceeds. Transaction costs relating to the equity component are recognised directly in equity. Transaction costs relating to the liability component are included in the carrying amount of the liability component and are amortised over the lives of the convertible notes using the effective interest method.

If a conversion option does not meet the definition of an equity instrument, it is classified as a derivative. The conversion option is initially recorded at fair value. The derivative is initially recorded at fair value with the difference between the fair value and the proceeds of issuance is recorded as a liability. The derivative is subsequently remeasured with changes to fair value recorded in the consolidated statement of profit or loss.

3.10 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either: in the principal market for the asset or liability or in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

All assets and liabilities, for which fair value is measured or disclosed in the consolidated historical financial information, are categorised within the fair value hierarchy, described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:

- Level 1—Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2—Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3—Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable

For assets and liabilities that are recognised in the consolidated historical financial information on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by reassessing categorisation (based on the lowest-level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

3.11 Cash and cash equivalents

Cash and cash equivalents comprise of cash in hand, demand deposits and also cash reserves retained as a bank security pledge in respect of bank guarantees (Note 15.2), with a maturity of three months or less that are subject to an insignificant risk of changes in their fair value.

The cash reserves retained as a bank security pledge in respect of bank guarantees are defined as restricted cash and held in designated bank deposits accounts to be used only for the purposes of the capital commitments. Release of cash from the accounts can only be made with the approval of the lender when specified expenditure milestones are met. The current and non-current classification of the bank security pledges is determined by the forecast expenditure of the capital commitments.

3.12 Inventories

Inventories comprise crude oil and by-product (Sulphur), consumables and other spare parts. Inventories are stated at the lower of cost and net realisable value. Cost is determined using the monthly weighted average cost method. The cost of finished goods and work in progress comprises raw materials, direct labour, other direct costs and related production overheads. It does not include borrowing costs. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and estimated costs necessary to make the sale. Spare parts consumed within a year are carried as inventory and recognised in profit or loss when consumed.

The Group assesses the net realisable value of the inventories at the end of each year and recognises in the consolidated statement of profit or loss the appropriate valuation adjustment if the inventories are overstated. When the circumstances that previously caused impairment no longer exist or when there is clear evidence of an increase in the inventories' net realisable value due to a change in the economic circumstances, the amount thereof is reversed.

3.13 Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount can be made. Where the Group expects a provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risk and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (when the effect of the time value of money is material).

- **Decommissioning provision**

The Group recognises a provision for decommissioning cost and, more specifically, a provision for future restoration of environment disturbed, as of the reporting date, as a result of past drilling activity and in line with the prevailing environmental legislation or binding practices. According to the Prinos concession agreement ratified by the Greek Law, the Group is obliged to plug only the wells opened resulting from own drilling activities. The amount recognised is the estimated cost of restoration, discounted to its present value. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related oil & gas property. The provision is measured at each reporting date and is appropriately adjusted to reflect the present value of the expenses required to fulfil the obligation. Changes in the estimated timing of restoration or restoration cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment.

The unwinding of the discount on the decommissioning provision is recognised in profit or loss within finance costs.

3.14 Government grants

Government grants on non-current assets acquisitions are recorded as deferred income and recognised as income on a systematic basis over the useful life of the asset.

Government grants that relate to expenses occurred are recognised in the profit or loss when they are received. If the relevant expense has not yet occurred the grant received is carried as deferred income in the consolidated statement of financial position until the expense occurs.

For the years 2014-2015 presented, the Group received government grants from Greek State Manpower Employment Organisation (OAED) which were provided to financially support Kavala Oil S.A. labour cost (please refer also to Note 12).

3.15 Revenue

Revenue is measured at the fair value of the consideration received or receivable, net of discounts and revenue indirect taxes.

Revenue is recognised when the amount of revenue can be measured reliably, it is probable that the economic benefits associated with the transaction will flow to the Group, the costs incurred or to be incurred can be measured reliably, and when also the recognition criteria for each of the Group's different activities have been met. These activity-specific recognition criteria are described below.

- **Sale of crude oil and by-products**

Revenue from sale of crude oil and by-products is recognised when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. This generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism.

- **Rendering of services**

Revenue from technical advisory services is recognised in the period in which the services are rendered by reference to the stage of completion of the specific service transaction, assessed on the basis of the actual service provided as a proportion of the total services to be provided.

- **Finance income**

Finance income is accrued by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

3.16 Retirement benefit costs

- **State-managed retirement benefit scheme**

  Payments made to state-managed retirement benefit schemes (e.g. Government Social Insurance Fund) are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution plan. The Group's contributions are expensed as incurred and are included in staff costs. The Group has no legal or constructive obligations to pay further contributions if the government scheme does not hold sufficient assets to pay all employees benefits relating to employee service in the current and prior periods.

- **Defined benefit plan**

  The Group operates an unfunded defined benefit plan in which a lump-sum amount is specified and is payable at the termination of employees' services based on such factors as the length of the employees' service and their salary. The liability recognised for the defined benefit plan is the present value of the defined benefit obligation at the reporting date.

  The cost of providing benefits is determined using the Projected Unit Credit Method, with actuarial valuations being carried out at each reporting date. These assumptions used in the actuarial valuations are developed by management with the assistance of independent actuaries.

  Service costs on the defined benefit plan are included in staff costs. Interest expense on the defined benefit liability is included in finance costs. Gains and losses resulting from other remeasurements of the defined benefit liability are included in other comprehensive income.

3.17 Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalisation.

Excluded from the above capitalisation policy are any qualifying assets that are inventories that are produced, in large quantities on a repetitive basis.

Borrowing costs include interest expense on loans, and bank overdrafts on an effective rate basis as well as other bank charges and are included in the consolidated statement of profit or loss.

3.18 Tax

Income tax expense represents the sum of current and deferred tax.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the consolidated historical financial information because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are never taxable or deductible. The Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

Deferred tax is recognised on temporary differences between the carrying amounts of assets and liabilities in the consolidated historical financial information and the corresponding tax bases used in the computation of taxable profit, based on tax rates that have been enacted or substantively enacted by the reporting date. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised. No deferred tax is recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Current and deferred tax assets and corresponding liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its tax assets and liabilities on a net basis.

Significant estimates are made in determining the tax liability for income taxes. The tax treatment of some transactions and calculations is uncertain and are yet to be agreed with the tax authorities in a number of jurisdictions. The Group recognises tax provision liabilities for anticipated tax issues based on if it is probable, defined as more likely than not, that additional taxes will be due. This assessment is based on all available evidence and, where appropriate, in the light of external advice. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax liability in the period in which such determination is made.

The Group has recognised deferred tax assets in respect of losses and other temporary differences to the extent that it is probable that there will be future taxable profits against which the losses and other temporary differences can be utilised. The Group has considered their carrying value at each balance sheet date and concluded that based on management's estimates, sufficient taxable profits will be generated in future years to recover such recognised deferred tax assets. These estimates are based on forecast performance and where tax losses are subject to expiration, the estimates take into account the expected reversal patterns of taxable temporary differences compared to the future reversal of deductible temporary differences.

3.19 Non-current assets and liabilities classified as held for sale and discontinued operations

Non-current assets (and disposal groups) classified as held for sale are measured at the lower of carrying amount and fair value less costs of disposal. Non-current assets and disposal groups are classified as held for sale if their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset (or disposal group) is available for immediate sale in its present condition. Management must be committed to the sale which should be expected to qualify for recognition as a completed sale within one year from the date of classification.

When the Group is committed to a sale plan involving loss of control of a subsidiary, all of the assets and liabilities of that subsidiary are classified as held for sale when the criteria described above are met, regardless of whether the Group will retain a non-controlling interest in its former subsidiary after the sale.

When the Group is committed to a sale plan involving disposal of an investment in an associate or, a portion of an investment in an associate, the investment, or the portion of the investment in the associate that will be disposed of is classified as held for sale when the criteria described above are met, and the Group discontinues the use of the equity method in relation to the portion that is classified a held for sale. Any retained portion of an investment in an associate that has not been classified as held for sale continues to be accounted for using the equity method. The Group discontinues the use of the equity method at the time of disposal when the disposal results in the Group losing significant influence over the associate. After the disposal takes place, the Group accounts for any retained interest in the associate in accordance with IAS 39 '*Financial Instruments: Recognition and Measurement*' unless the retained interest continues to be an associate, in which case the Group uses the equity method (see the accounting policy regarding investments in associates above) (please refer also to Note 9).

3.20 Equity, reserves and dividend payments

Share capital represents the nominal (par) value of shares that have been issued. Share premium includes any premiums received on issue of share capital. Any transaction costs associated with the issuing of shares are deducted from share premium, net of any related income tax benefits.

Other components of equity include the following:

- remeasurement of net defined benefit liability—comprises the actuarial losses from changes in demographic and financial assumptions and the return on plan assets (see Note 3.16)

- translation reserve—comprises foreign currency translation differences arising from the translation of financial statements of the Group's foreign entities into Euro and translation reserves from the translation to Group's presentation currency US$ (see Note 3.2)

Retained earnings includes all current and prior period retained profits.

All transactions with owners of the parent are recorded separately within equity.

Dividend distributions payable to equity shareholders are included in other liabilities when the dividends have been approved in a general meeting prior to the reporting date.

3.21 Standards issued but not yet adopted which are applicable to the Group

The following standards and interpretations, which have not been applied in the HFI, were in issue but not yet effective (and in some cases have not yet been adopted by the EU):

IFRS 9	Financial Instruments (effective for periods beginning on or after 1 January 2018)
IFRS 15	Revenue from Contracts with Customers (effective for periods beginning on or after 1 January 2018)
IFRS 16 Leases	Leases (applied to annual reporting period beginning on or after 1 January 2019)
IFRIC 23	Uncertainty over Income Tax Treatments (effective for periods beginning on or after 1 January 2019)
IAS 28 (Amendments)	Long-term Interests Associates and Joint Ventures (effective for periods beginning on or after 1 January 2019)
IFRIC 22	Foreign Currency Transactions and Advance Consideration (issued by the IASB, but not yet adopted by the EU)
IFRS 2 (Amendments)	Classification and Measurement of Share-based Payment Transactions (issued by the IASB, but not yet adopted by the EU)
IFRS 10 and IAS 28 (Amendments)	Sale or Contribution of Assets between an Investor and its Associate or Joint Venture (issued by the IASB, but not yet adopted by the EU)

The Group's evaluation of the effect of adoption of these standards is ongoing but it is not currently anticipated that the adoption of the Standards and Interpretations listed above will have a material impact on the financial statements of the Group in future periods.

4. Critical accounting estimates and judgements

The preparation of this consolidated historical financial information in conformity with IFRS requires the use of accounting estimates and assumptions, and also requires management to exercise its judgement, in the process of applying the Group's accounting policies.

Estimates, assumptions and judgement applied are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Although these estimates, assumptions and judgement are based on management's best knowledge of current events and actions, actual results may ultimately differ.

4.1 Critical judgements in applying the Group's accounting policies

The following are significant management judgements in applying the accounting policies of the Group that have the most significant effect on the consolidated historical financial information:

Determination of a Business

Determination of whether a set of assets acquired and liabilities assumed constitute a business may require the Group to make certain judgements. A business is a group of assets that includes inputs, outputs and processes

that are capable of being managed together to provide a return to the Group and its shareholders. Classification of an acquisition as a business combination or an asset acquisition depends on whether the assets acquired constitute a business. Whether an acquisition is classified as a business combination or asset acquisition can have a significant impact on the entries made on or after acquisition.

In 2016, the Group acquired the remaining 50% of the equity in Energean Israel Limited. The Group concluded that the acquisition did not meet the definition of a business since in acquisition the fair value of the gross assets acquired was not concentrated in a single identifiable asset, and accordingly, the acquisition was accounted for as the acquisition of an asset. The accounting and further detail on the judgement made is set out in Note 9.

Functional Currency

The functional currency for the Company and each of its subsidiaries is the currency of the primary economic environment in which the entity operates. Note 3.2 describes the functional currency of each of the entities within the Group. The determination of the functional currency of Energean Oil and Gas S.A. involves certain judgements to determine the primary economic environment. As Energean Oil and Gas S.A.'s capital expenditure, payroll cost, energy costs and exploration and evaluation costs are all predominantly denominated in Euro, the Group has determined that the functional currency of the company is the Euro. The Group reconsiders the functional currency of its entities if there is a change in events and conditions which determined the primary economic environment.

4.2 Estimation uncertainty

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities, are discussed below:

Fair value measurements and valuation processes

Some of the Group's assets and liabilities are measured at fair value for financial reporting purposes. In estimating the fair value of an asset or a liability the Group uses market-observable data to the extent that it is possible. Where level 1 inputs are not available, as is the case for estimating a fair value for the convertible loan notes (see Note 9) and the option to purchase Energean Israel Class B shares (see Note 33.4) the Group has used a combination of level 2 and level 3 inputs to estimate the fair value.

The Chief Financial Officer reports the valuations to the board of directors of the Group every six months to explain the cause of fluctuations in the fair value of the assets and liabilities.

Information about the valuation technique and inputs used in determining the fair value of the convertible loan notes and the option to purchase Energean Israel Class B shares is disclosed in Note 36.2.

Impairment of Non-Financial Assets

- Impairment assessment of property, plant and equipment

  The Group assesses impairment at each reporting date by evaluating conditions specific to the Group that may lead to impairment of assets. Where an indicator of impairment exists, the recoverable amount (which is the higher of fair value less costs to sell and value in use) of the cash-generating unit to which the assets belong is then estimated based on the present value of future discounted cash flows. For oil and gas assets, the expected future cash flow estimation is based on a number of factors, variables and assumptions, the most important of which are estimates of reserves, future production profiles, oil prices and costs. In most cases, the present value of future cash flows is most sensitive to estimates of future oil price, estimates of reserves, estimates of development costs and discount rates. A change in the assumptions could materially change the recoverable amount. In the event that future circumstances vary from these assumptions, the recoverable amount of the Group's development and production assets could change materially and result in impairment losses or the reversal of previous impairment losses.

Further details of the Group's economic environment are provided in Note 35. Based on the evaluation performed, no further provisions or impairment charges are deemed necessary as of the reporting date. Further details about the carrying value of property, plant and equipment are shown in Note 6 of the consolidated financial information.

- Impairment assessment of exploration and evaluation costs

  The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement in determining whether that future economic benefits are likely either from future exploitation or sale or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves or whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when this new information becomes available. Further details about the carrying value of exploration and evaluation costs are shown in Note 6 of the consolidated financial information.

Hydrocarbon reserve and resource estimates

The Group's oil and gas development and production properties are depreciated on a unit of production basis at a rate calculated by reference to developed and undeveloped proved and probable commercial reserves (2P developed and undeveloped) which are estimated to be recoverable with existing and future developed facilities using current operating methods, the determined in accordance with (Petroleum Resources Management System published by Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists).

Commercial reserves are determined using estimates of oil in place, recovery factors and future oil prices. The level of estimated commercial reserves is also a key determinant in assessing whether the carrying value of any of the Group's oil and gas properties has been impaired.

As the economic assumptions used may change and as additional geological information is produced during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results which include:

- Depreciation and amortisation charges in profit or loss may change where such charges are determined using the units of production method, or where the useful life of the related assets change
- Impairment charges in profit or loss
- Provisions for decommissioning may change—where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities
- The recognition and carrying value of deferred tax assets and liabilities may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets

Retirement benefit obligation

The cost of defined benefit pension plans is determined using actuarial valuations. The actuarial valuation involves making assumptions about discount rates, future salary increases, mortality rates and future pension increases where necessary. The Group sets these assumptions with the assistance of independent professional actuaries. Due to the long-term nature of these plans, such estimates are subject to significant uncertainty. The assumptions used may vary from year to year which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets. Further details are shown in Note 20 of the consolidated financial information.

Income taxes

Significant estimates are made in determining the tax liability for income taxes. The tax treatment of some transactions and calculations is uncertain and are yet to be agreed with the tax authorities in a number of jurisdictions. The Group recognises tax provision liabilities for anticipated tax issues based on if it is probable, defined as more likely than not, that additional taxes will be due. This assessment is based on all available evidence and, where appropriate, in the light of external advice. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax liability in the period in which such determination is made.

The Group has recognised deferred tax assets in respect of losses and other temporary differences to the extent that it is probable that there will be future taxable profits against which the losses and other temporary differences can be utilised. The Group has considered their carrying value at each balance sheet date and concluded that based on management's estimates, sufficient taxable profits will be generated in future years to recover such recognised deferred tax assets. These estimates are based on forecast performance and where tax losses are subject to expiration, the estimates take into account the expected reversal patterns of taxable temporary differences compared to the future reversal of deductible temporary differences.

Deferred Tax Assets recognised from carried forward unused tax losses for the Group amounted to US$76,013 for the ten months ended 31 October 2017 (ten months ended 31 October 2016: US$61,132, years ended 31 December 2016: US$56,296, 2015: US$42,817, 2014: US$26,882).

The Directors regard the deferred tax asset in relation to tax losses and other temporary differences as recoverable, despite the loss-making situation that currently exists, based on its best estimate of future sources of taxable income of the Group.

Recoverability of Kavala subsidies receivable

In December 2015, Kavala Oil SA filed a petition against OAED, the public body for employment and social inclusion in Greece, and the Greek state itself, seeking the payment of €2.5 million (plus interest). This claim is based on the provisions of Art. 21 of the Law Act No 1767/1988 and the Ministerial Decree No 31370/1988, by which Kavala Oil SA believes it was entitled to receive the abovementioned sum as financial support under the action plan (co-funding by national and EU instruments) for promoting sustainable employment in underdeveloped or deprived districts of Greece, such as the area of Kavala.

Following several postponements of the hearing initiated by the Greek state, the hearing took place on 14 June 2017. The Group is of the view, based on legal advice, this petition will prevail and has therefore included a balance within trade and other receivables (Note 12).

5. Segmental Reporting

The information reported to the Group's Chief Executive Officer and Chief Financial Officer (Chief Operating Decision Makers) for the purposes of resource allocation and assessment of segment performance is focused on five operating segments: Greece (including production asset of Prinos and non producing exploration assets of Ioannina and Katakolo), Israel (including the 50% of Karish and Tanin assets), Egypt (including non producing exploration asset of West Kom Ombo), Montenegro (including two non producing exploration assets) and New Ventures. Factors considered to identify the operating segments of the Group are geographical and stage of development.

The operating results of each operating segment are regularly reviewed by the Group's Chief Operating Decision Makers in order to make decisions about the allocation of resources and to assess their performance. The Group's Chief Operating Decision Makers evaluates segmental performance on the basis of adjusted EBITDAX, which is defined as profit/(loss) from continuing operations before tax less depreciation and amortization, exploration and evaluation expenses, other income, other expenses, finance costs, finance income, gain / (loss) on derivative instruments and net foreign exchange gain/(loss). Adjusted EBITDAX is used by the CODM as the profit measure for the review of the segment operations. Greece segment comprises the production asset of Prinos area (including Prinos, Prinos North, South Kavala Epsilon fields) and north-east Greece (exploration assets of Ioannina and Katakolo). The Group's reportable segment under IFRS 8 *Operating Segments* is Greece. Segments that do not exceed the quantitative thresholds for reporting information about operating segments have been included in Other.

The following tables present revenue and certain asset information regarding the Group's reportable segments for the ten months ended 31 October 2017, 31 October 2016 and years ended 31 December 2016, 31 December 2015, 31 December 2014.

Segment revenues, results and reconciliation to profit before tax

The following is an analysis of the Group's revenue, results and reconciliation to profit before tax by reportable segment:

	Greece	Other	Intercompany transactions & elimination adjustments	Total
Ten months ended 31 October 2017				
Revenue	37,351	3,187	(2,113)	38,425
Adjusted EBITDAX	12,852	(517)	6	12,341
Reconciliation to profit /(loss) before tax:				
Depreciation and amortisation expenses	(14,859)	(72)	—	(14,931)
Exploration and evaluation expenses	(102)	(7,011)	63	(7,050)
Other expenses	(9,337)	(517)	84	(9,770)
Other income	754	1,590	(175)	2,169
Finance income	21,879	20,734	(42,599)	14
Finance costs	(25,502)	(38,472)	42,842	(21,132)
Gain on derivative	—	24,109	—	24,109
Net foreign exchange gain / (loss)	27,822	171	(372)	27,621
Profit / (loss) from continuing operations before tax	**13,507**	**15**	**(151)**	**13,371**
Ten months ended 31 October 2016 (unaudited)				
Revenue	31,187	2,180	(2,180)	31,187
Adjusted EBITDAX	12,245	730	(1,395)	11,580
Reconciliation to profit /(loss) before tax:				
Depreciation and amortisation expenses	(15,539)	—	—	(15,539)
Exploration and evaluation expenses	(94)	(1,022)	—	(1,116)
Other expenses	(1,729)	(6)	0	(1,735)
Other income	503	55	0	558
Finance income	323	21,757	(21,757)	323
Finance costs	(21,150)	(21,508)	21,661	(20,997)
Net foreign exchange gain / (loss)	340	28	131	499
Profit / (loss) from continuing operations before tax	**(25,101)**	**34**	**(1,360)**	**(26,427)**
Year ended 31 December 2016				
Revenue	39,724	2,985	(2,985)	39,724
Adjusted EBITDAX	16,072	999	(869)	16,202
Reconciliation to profit /(loss) before tax:				
Depreciation and amortisation expenses	(21,499)	—	—	(21,499)
Exploration and evaluation expenses	—	(1,953)	820	(1,133)
Other expenses	(4,480)	(208)	—	(4,688)
Other income	387	55	(194)	248
Finance income	327	29,375	(29,375)	327
Finance costs	(30,068)	(28,730)	29,487	(29,311)
Net foreign exchange gain / (loss)	(9,982)	(96)	35	(10,043)
Profit / (loss) from continuing operations before tax	**(49,243)**	**(558)**	**(96)**	**(49,897)**
Year ended 31 December 2015				
Revenue	28,423	11	—	28,434
Adjusted EBITDAX	(601)	(608)	—	(1,209)
Reconciliation to profit /(loss) before tax:				
Depreciation and amortisation expenses	(7,577)	(4)	—	(7,581)
Exploration and evaluation expenses	(252)	—	—	(252)
Other expenses	(2,769)	(40)	(252)	(3,061)
Other income	265	—	—	265
Finance income	91	22,970	(22,970)	91

	Greece	Other	Intercompany transactions & elimination adjustments	Total
Finance costs	(20,160)	(22,968)	22,990	(20,138)
Net foreign exchange gain / (loss)	(12,943)	846	(19)	(12,116)
Profit / (loss) from continuing operations before tax	**(43,946)**	**196**	**(251)**	**(44,001)**
Year ended 31 December 2014				
Revenue	41,885	511	(152)	42,244
Adjusted EBITDAX	11,081	68	—	11,149
Reconciliation to profit /(loss) before tax:				
Depreciation and amortisation expenses	(7,719)	(4)	—	(7,723)
Exploration and evaluation expenses	(308)	—	—	(308)
Other expenses	(7,586)	—	104	(7,482)
Other income	10,859	15,333	—	26,192
Finance income	179	13,615	(13,628)	166
Finance costs	(15,030)	(14,819)	11,566	(18,283)
Net foreign exchange gain / (loss)	(11,440)	1,250	(1)	(10,191)
Profit / (loss) from continuing operations before tax	**(19,964)**	**15,443**	**(1,959)**	**(6,480)**

6. Property, plant and equipment

Property, plant & equipment at cost	Land and buildings	Property under construction	Vessel and transportation means	Plant and machinery	Furniture, fixtures and equipment	Oil and gas properties	Total
1 January, 2014	**399**	**6,912**	**1,353**	**18,371**	**1,514**	**262,216**	**290,765**
Additions	77	21,415	4,880	387	81	5,182	32,022
Change in environmental rehabilitation provision	—	—	—	—	—	(59)	(59)
Foreign exchange impact	(52)	(2,757)	(111)	(1,578)	(143)	(29,709)	(34,350)
31 December 2014	**424**	**25,570**	**6,122**	**17,180**	**1,452**	**237,630**	**288,378**
Additions	118	7,609	496	32,354	146	19,585	60,308
Capitalised depreciation	—	—	—	—	—	2,339	2,339
Change in environmental rehabilitation provision	—	—	—	—	—	116	116
Transfer	—	(6,506)	—	—	—	6,506	—
Foreign exchange impact	(52)	(2,432)	(679)	(1,578)	(143)	(29,142)	(34,026)
31 December 2015	**490**	**24,241**	**5,939**	**47,956**	**1,455**	**237,034**	**317,115**
Additions	20	972	3	663	168	60,902	62,728
Exploration cost transferred from intangible assets	—	—	—	—	—	1,154	1,154
Capitalised depreciation	—	—	—	—	—	7,014	7,014
Disposals	—	—	(4,574)	—	—	—	(4,574)
Change in environmental rehabilitation provision	—	—	—	—	—	1,205	1,205
Foreign exchange impact	(16)	(816)	(128)	(1,556)	(44)	(10,647)	(13,207)
At 31 December 2016	**494**	**24,397**	**1,240**	**47,063**	**1,579**	**296,662**	**371,435**

Property, plant & equipment at cost	Land and buildings	Property under construction	Vessel and transportation means	Plant and machinery	Furniture, fixtures and equipment	Oil and gas properties	Total
At 1 January 2016	**490**	**24,241**	**5,939**	**47,956**	**1,455**	**237,034**	**317,115**
Additions	1	4,118	—	440	105	47,406	52,070
Exploration cost transferred from intangible assets	—	—	—	—	—	1,312	1,312
Capitalised depreciation	—	—	—	—	—	3,050	3,050
Disposals	—	—	(4,749)	—	—	—	(4,749)
Change in environmental rehabilitation provision	—	—	—	—	—	452	452
Foreign exchange impact	14	(57)	32	(523)	(286)	1,221	401
At 31 October 2016 (unaudited)	**505**	**28,302**	**1,222**	**47,873**	**1,274**	**290,475**	**369,651**
At 1 January 2017	**494**	**24,397**	**1,240**	**47,063**	**1,579**	**296,662**	**371,435**
Additions	—	6,779	211	1,252	110	42,273	50,625
Capitalised depreciation	—	—	—	—	—	1,974	1,974
Change in environmental rehabilitation provision	—	118	—	—	—	1,054	1,172
Foreign exchange impact	64	6,229	394	28	(147)	23,278	29,846
At 31 October 2017	**558**	**37,523**	**1,845**	**48,343**	**1,542**	**365,241**	**455,052**

Accumulated depreciation	Land and buildings	Property under construction	Vessel and transportation means	Plant and machinery	Furniture, fixtures and equipment	Oil and gas properties	Total
At 1 January 2014	**150**	**—**	**1,167**	**7,083**	**1,209**	**116,254**	**125,863**
Charge for the year	38	—	92	642	97	6,759	7,628
Impairments	—	—	1	4,279	280	—	4,560
Disposal	—	—	(1)	(30)	(280)	—	(311)
Foreign exchange impact	(22)	—	(149)	(912)	(122)	(14,461)	(15,666)
31 December 2014	**166**	**—**	**1,110**	**11,062**	**1,184**	**108,552**	**122,074**
Charge for the year	34	—	256	348	94	6,695	7,427
Impairments	—	39	—	—	—	—	39
Capitalised depreciation to Oil and gas properties	—	—	—	2,339	—	—	2,339
Foreign exchange impact	(22)	—	(149)	(913)	(123)	(14,566)	(15,773)
31 December 2015	**178**	**39**	**1,217**	**12,836**	**1,155**	**100,681**	**116,106**
Charge for the year	56	—	115	411	100	20,673	21,355
Disposals	—	—	(299)	—	—	—	(299)
Impairments	—	1,007	—	940	—	—	1,947
Capitalised depreciation to Oil and gas properties	—	—	—	7,014	—	—	7,014
Foreign exchange impact	(7)	45	39	(807)	(32)	(4,106)	(4,868)
31 December 2016	**227**	**1,091**	**1,072**	**20,394**	**1,223**	**117,248**	**141,255**

Accumulated Depreciation	Land and buildings	Property under construction	Vessel and transportation means	Plant and machinery	Furniture, fixtures and equipment	Oil and gas properties	Total
At 1 January 2016	**178**	**39**	**1,217**	**12,836**	**1,155**	**100,681**	**116,106**
Charge for the period	32	—	110	328	84	14,859	15,413
Capitalised depreciation to Oil and gas properties	—	—	—	3,050	—	—	3,050
Disposal	—	—	(310)	—	—	—	(310)
Foreign exchange impact	(49)	—	(7)	(233)	(274)	(412)	(975)
At 31 October 2016 (unaudited)	**161**	**39**	**1,010**	**15,981**	**965**	**115,128**	**133,284**
At 1 January 2017	**227**	**1,091**	**1,072**	**20,394**	**1,223**	**117,248**	**141,255**
Charge for the period	49	—	28	482	77	14,119	14,755
Capitalised depreciation to Oil and gas properties	—	—	—	1,974	—	—	1,974
Impairment	—	111	—	—	—	—	111
Foreign exchange impact	(30)	(32)	378	(2,124)	(173)	8,620	6,639
At 31 October 2017	**246**	**1,170**	**1,478**	**20,726**	**1,127**	**139,987**	**164,734**
Net Carrying Amount At 31 October 2017	**312**	**36,353**	**367**	**27,617**	**415**	**225,253**	**290,318**
At 31 October 2016 (unaudited)	**344**	**28,263**	**212**	**31,892**	**309**	**175,347**	**236,367**
At 31 December 2016	**267**	**23,306**	**168**	**26,669**	**356**	**179,414**	**230,180**
At 31 December 2015	**312**	**24,202**	**4,722**	**35,120**	**300**	**136,353**	**201,009**
At 31 December 2014	**258**	**25,570**	**5,012**	**6,118**	**268**	**129,078**	**166,304**

The above oil and gas properties related to the Greek segment (the fields of Prinos, Prinos North and Epsilon) are depreciated at the same rate (see Note 3.5)

Borrowing costs capitalised for qualifying assets, included in "additions" of oil & gas properties and property under construction, for the ten months ended 31 October 2017 amounted to US$1,056 (ten months ended 31 October 2016: US$3,800, years ended 31 December 2016: US$3,992, 2015: US$3,553, 2014: US$833). The interest rates used:

- 7.03% (for the ten month period ended 31 October 2017)
- 15.66% (for the period 1 January 2016 to 31 May 2016) and 6.97% (for the period 1 June 2016 to 31 October 2016)
- 12.6% (for the period 1 January 2015 to 15 April 2015) and 15.47% (for the period 16 April 2015 to 31 December 2015)
- 11.96% (for the year ended 31 December 2014)

During the year ended 31 December 2014 and in view of its future drilling campaigns, the Group acquired and initiated the upgrade work of a Drilling Rig (Energean Force). The Group has issued a first preferred mortgage on the aforementioned Energean Force, in favour of European Bank for Reconstruction and Development (EBRD) (see Note 17). The depreciation charge of the Energean Force has been capitalised in the oil and gas properties.

The Group recorded impairment and write-off charges on PP&E of US$111 for the ten months ended 31 October 2017 (ten months ended 31 October 2016 US$nil, years ended 31 December 2016: US$1,947, 2015: US$39, 2014: 4,560). The impairment charges relate to machinery and other equipment used in operations. The write-off in 2014 related to a drilling rig which was retired and scrapped.

Depreciation expense for the periods has been recognised as follows:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Cost of sales	14,480	15,261	21,218	7,292	7,424
Administration expenses	274	153	137	136	204
Capitalised depreciation in oil & gas properties	1,974	3,050	7,014	2,339	—
Total	**16,728**	**18,464**	**28,369**	**9,767**	**7,628**

6.1 Loss from disposal of property, plant and equipment

In the cash flow statement, loss from the disposal of sale of property, plant and equipment comprise:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Supply vessel (net book value)	—	4,439	4,275	—	—
Proceeds from sale	—	(2,850)	(2,698)	—	—
Loss from disposal	—	1,589	1,577	—	—

7. Intangible assets

Intangibles at Cost	Computers & Software	Exploration and evaluation costs	Total
At 1 January 2014	**700**	**6**	**706**
Additions	341	1,259	**1,600**
Foreign exchange impact	(122)	(2)	**(124)**
31 December 2014	**919**	**1,263**	**2,182**
Additions	236	2,875	**3,111**
Foreign exchange impact	(74)	(119)	**(193)**
31 December 2015	**1,081**	**4,019**	**5,100**
Additions	299	5,201	**5,500**
Foreign exchange impact	(81)	(103)	**(184)**
Exploration cost transferred to Oil and gas properties	—	(1,154)	**(1,154)**
31 December 2016	**1,299**	**7,963**	**9,262**

Intangibles at Cost	Computers & software	Exploration and evaluation costs	Total
At 1 January 2016	**1,081**	**4,019**	**5,100**
Additions	147	4,822	**4,969**
Exploration cost transferred to Oil & gas properties	—	(1,199)	**(1,199)**
Foreign exchange impact	(109)	(69)	**(178)**
At 31 October 2016 (unaudited)	**1,119**	**7,573**	**8,692**
At 1 January 2017	**1,299**	**7,963**	**9,262**
Additions	273	2,549	**2,822**
Write-off of exploration and evaluation costs	—	(6,646)	**(6,646)**
Disposal of asset	—	(991)	**(991)**
Exchange differences	48	345	**393**
At 31 October 2017	**1,620**	**3,220**	**4,840**

Accumulated Amortisation	Computers & software	Exploration and evaluation costs	Total
At 1 January 2014	**536**	**—**	**536**
Charge for the year	95	—	**95**
Impairment	—	199	**199**
Foreign exchange impact	(107)	—	**(107)**
31 December 2014	**524**	**199**	**723**
Charge for the year	153	—	**153**
Impairment	—	61	**61**
Foreign exchange impact	(29)	(11)	**(40)**
31 December 2015	**648**	**249**	**897**
Charge for the year	144	—	**144**
Foreign exchange impact	(48)	(9)	**(57)**
31 December 2016	**744**	**240**	**984**

Accumulated Amortisation	Computers & software	Exploration and evaluation costs	Total
At 1 January 2016	**648**	**249**	**897**
Charge for the period	125	—	**125**
Foreign exchange impact	(44)	9	**(35)**
31 October 2016 (unaudited)	**729**	**258**	**987**
At 1 January 2017	**744**	**241**	**985**
Charge for the period	177	—	**177**
Foreign exchange impact	37	25	**62**
31 October 2017	**958**	**266**	**1,224**
Net Carrying Amount			
At 31 October 2017	**662**	**2,954**	**3,616**
At 31 October 2016 (unaudited)	**390**	**7,315**	**7,705**
At 31 December 2016	**555**	**7,723**	**8,278**
At 31 December 2015	**433**	**3,770**	**4,203**
At 31 December 2014	**395**	**1,064**	**1,459**

Disposal of Exploration and evaluation cost

In March 2017, the Group agreed to farm out a 60% working interest and operatorship of the Ioannina licence to Repsol. The Group retains a 40% working interest as of 31 October 2017 (Note 1.2). According to Farm out agreement:

1. On the completion date Repsol paid to the Group the consideration of US$1 million for all past costs regarding the licence.
2. Repsol will conduct the exploration of the Ioannina block, providing 90% of the committed investment up to US$25 million and 60% thereafter in exchange for a 60% interest.

The disposal of exploration and evaluation cost included in the ten month period ended 31 October 2017, relates to 60% of past expenditure in Ioannina lease area. No profit in the period ended 31 October 2017 was recorded for the above transaction.

Write-off and impairments

The Group recognised US$6,646 million in exploration and evaluation expenses in the ten months ended 31 October 2017, relating to exploration expenditure for West Kom Ombo in Egypt. West Kom Ombo is an exploration block in Upper Egypt, the licence for which expired on 2 October 2017. There are no recoverable costs associated with West Kom Ombo and the asset has been fully written off. In July 2017, Energean International Limited drilled the Apis-1 well which was plugged and abandoned.US$61 and US$199 of impairment charges recorded for the year ended 31 December 2015 and December 2014, corresponds to Exploration and Evaluation costs incurred for East Magawish licence in Egypt. The Group relinquished the area in 2015 due to no commercial hydrocarbon discovery.

Amortisation and impairment expenses and write-offs for the period have been recognised in profit or loss as follows:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Write-off of exploration and evaluation costs	6,646	—	—	—	—
Impairment of exploration and evaluation costs	—	—	—	61	199
Administration expenses	177	125	144	153	95
Total	**6,823**	**125**	**144**	**214**	**294**

8. Subsidiary companies

8.1 Details of subsidiaries

Name of subsidiary	Country of incorporation / registered office	Principal activities	At 31 October 2017 (%)	At 31 October 2016 (%)	At 31 December 2016 (%)	At 31 December 2015 (%)	At 31 December 2014 (%)
Energean E&P Holdings Ltd[1]	36 Vyronos Avenue, 1506 Nicosia Cyprus	Holding Company	100	N/A	N/A	N/A	N/A
Energean Oil & Gas S.A[2]	32, Kifissias Ave. 151 25 Marousi Athens, Greece	Oil and gas exploration, development and production	100	100	100	100	100
Energean Drilling S.A.[3]	32, Kifissias Ave. 151 25 Marousi Athens Greece	Oil and gas exploration, development and production	N/A	N/A	N/A	100	100
Kavala Oil S.A. [4]	P.O. BOX 8, 64006 Nea Karvali Kavala, Greece	Provision of oil and gas support services	99.92	99.92	99.92	99.92	67
Energean International Limited[5]	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	100	100	100	100	100
Energean Israel Limited[6] (Note 9)	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	0	100	100	50	50
Energean Montenegro Limited[7]	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	100	100	100	N/A	N/A

(1) Energean E&P Holdings Limited was the holding company of the Group until 30 June 2017, when it became a wholly-owned subsidiary of the Energean Oil and Gas PLC.
(2) Energean Oil and Gas S.A is a subsidiary of Energean E&P Holdings Limited. On 8 December 2014, Energean Oil and Gas S.A exercised its right to convert its preference shares in Kavala Oil S.A. to common shares to hold a 99.9% participating interest. This conversion was effective in March 2015 (as described in Note 10).
(3) On 15 June 2016 Energean Drilling S.A was merged with Energean Oil and Gas S.A.
(4) Kavala Oil S.A. is a subsidiary of Energean Oil and Gas S.A.
(5) Energean International Limited is a subsidiary of Energean E&P Holdings Limited.
(6) As of 31 October 2017, the Group owns 0% of the economic interest and 50% of the voting rights in Energean Israel Limited. As of 31 December 2016, the Group owned 100% of the economic interest in Energean Israel Limited. As of 31 December 2015 and 2014, the Group owned 50% of the economic interest in Energean Israel Limited. The Group's interest in the share capital of Energean Israel Limited is described in Note 9.
(7) On 29 June 2016 Energean Montenegro Limited was formed as the licence holding vehicle for the application and subsequent award of Blocks 26 and 30 in Montenegro.

8.2 Corporate information and activities of main subsidiaries

Energean Oil & Gas S.A.

Energean Oil & Gas S.A. is engaged in the exploration, extraction and trading of oil and gas. Energean Oil & Gas S.A was established in 2007 in Greece.

In December 2007, Energean Oil & Gas S.A acquired Kavala Oil SA (Kavala Oil), the sole oil and gas production company in Greece under a licence granted by the Greek State under Law 2779/1999 (the Licence) for the exploration and production of the crude oil & gas reserves of Prinos and South Kavala field (the exploitation areas).

In June 2009, the exploitation areas were assigned by Kavala Oil to Energean Oil and Gas S.A, under an assignment agreement entered into in line with the licence. Under the assignment agreement Kavala Oil remained the Group operating company in respect of the exploitation areas of Prinos. From June 2009 Energean Oil and Gas S.A is the concession holder of the Prinos, Prinos North, Epsilon and South Kavala oil & gas licences as per the law 2779/1999 as amended via the law no. 4135/2013. Both Energean Oil and Gas S.A and Kavala Oil remain jointly and severally liable towards the Greek State in complying with all terms and obligations.

Energean Oil and Gas S.A also holds a 60% working interest in the Ioannina onshore block, Western Greece, as well as a 100% working interest in the 25-year exploitation licence of the Katakolo offshore field.

Energean Israel Limited

Please refer to Note 9 below.

9. Investments in Energean Israel

9.1 Details of the joint venture

Energean Israel Limited (formerly Ocean Energean Oil and Gas Limited) was incorporated in Cyprus on 22 July 2014 as a private company with limited liability under the Companies Law, Cap. 113. Its registered office is at Vyronos 36, Nicosia Tower Center, 8th floor, 1096, Nicosia, Cyprus.

The principal activity of the Energean Israel Limited is to act, work and operate as an international offshore drilling contractor and/or oil operator, providing oilfield services for offshore oil and gas mining, exploration and production.

As of 31 December 2015 and 2014, Energean Israel Limited was a 50% investment in a joint venture. On 16 August 2016, the Group acquired the remaining 50% of the share capital of Energean Israel Limited for the purpose of investing in the Karish and Tanin licences. The acquisition of the additional 50% did not, however, meet the definition of a business combination as Energean Israel Limited had 0 employees, did not own the Karish and Tanin licences, and the development plan for the offshore fields had not commenced.

Below represents the consideration transferred to acquire the remaining share capital of Energean Israel Limited on 16 August 2016:

Consideration transferred	
Cash paid	41
Fair value of equity interest already held	40
Total consideration transferred	81

Assets and liabilities acquired	**Fair value**
Trade and other receivables	2
Cash at bank and in hand	88
Trade and other payables	(9)
Net assets acquired	81
Cash consideration paid	(41)
Cash and cash equivalents acquired	88
Net cash flow on acquisition	47

Acquisition of leasehold rights

On 16 August 2016, Energean Israel Limited entered into a Sale and Purchase Agreement to acquire interests in each of the Tanin and Karish offshore Israel leases issued by the Israel Petroleum Commissioner on 24 December 2015.

Following approval from the Israel Petroleum Commissioner obtained in December 2016, Energean Israel Limited has paid an initial and closing payment of forty million dollars (US$40,000) and has assumed the obligation to pay the remainder of the consideration being a total additional amount of one hundred and eight million and five hundred thousand dollars (US$108,500) in ten equal annual payments and ongoing royalties to the sellers. The additional consideration is due the earlier of the date on which a final investment decision of Energean Israel Limited has been made or the date on which aggregate expenditures in connection with the leases exceed one hundred and fifty million dollars (US$150,000). The US$108,500 remaining consideration is not recognised in the consolidated historical financial information and does not form part of the consideration.

In August 2016, the Energean E&P Holdings Limited entered into loan agreements with its founding shareholders Oilco Investments, Growthy Holdings and Adobelero Holdings for loans of US$4,750, US$4,750 and US$500 respectively to fund the US$10,000 initial payment pursuant to the sale and purchase agreement for the acquisition of the Karish and Tanin rights. Each of the loans bears interest at 2.0% and had an initial term of 90 days. On 21 December 2016, the Group entered into a subscription agreement with Kerogen Capital Limited (Kerogen), a private equity fund manager focused on oil and gas, for the investment of US$50 million to Energean Israel Limited. The initial capital was funded by a US$35 million convertible loan in December 2016 and a further US$5 million loan in the first quarter of 2017, to be converted to equity, together with a further equity investment by Kerogen of US$10 million subject to (i) the approval from the Petroleum Commissioner and (ii) the closing of the sale and purchase of the subject interest in accordance with the provisions of the Delek sale and purchase agreement. The loan bears no interest and was repayable by 19 June 2017 in the case that no conversion occurred. The net proceeds received from the issue of the Kerogen convertible loan have been allocated between the financial liability component ($34,167 as of 31 December 2016) and an equity component ($737k as of 31 December 2016). The conversion reserve represents the difference between the fair value of the discounted cash outflows to repay the loan from Kerogen, discounted using the market interest rate, and the total proceeds from the convertible loans of US$40 million.

On 13 June 2017 the Kerogen Convertible loan interim facility and founding shareholders loans were discharged in consideration for the issue of shares in Energean Israel Limited, whereby Kerogen acquired a 50% equity voting interest and a 50% economic interest and the founding shareholders acquired a 50% economic interest in Energean Israel Limited. Energean E&P Holdings Limited retained the remaining 50% of the voting rights of Energean Israel. The shareholders' agreement governing the control and management of Energean Israel Limited specifies that the Group's strategy for the development and operation of the Karish and Tanin fields and the implementation of such strategy are subject to consulting with and obtaining the consent of Kerogen. Accordingly, Energean Israel Limited was classified as a discontinued operations and assets and liabilities held for sale as of 31 December 2016 and ceased to be a subsidiary of the Group on 13 June 2017. Energean Israel Limited was deconsolidated at 13 June 2017.

9.2 Discontinued operations

At 31 December 2016, Energean Israel Limited was presented as a wholly owned subsidiary of Energean E&P Holdings Limited. Based on the Kerogen convertible loan and founding shareholder loans as described above, the Group lost control of Energean Israel Limited on 13 June 2017 and was therefore presented as a discontinued operation in accordance with IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations*.

The results of the discontinued operations, which have been included in the consolidated statement of profit or loss, were as follows:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Administration expenses	(1,112)	(71)	(107)	—	—
Exploration and evaluation expenses	—	(13)	—	—	—
Operating loss	**(1,112)**	**(84)**	**(107)**	**—**	**—**
Finance costs	(304)	(24)	(126)	—	—
Finance income	11	—	—	—	—
Income from foreign exchange transactions	2	—	4	—	—
Share of results of joint venture	—	—	—	(66)	(104)
Profit / (loss) from discontinued operations	**(1,403)**	**(108)**	**(229)**	**(66)**	**(104)**

A US$1.5 million gain on disposal of the subsidiary was recognised in other income in profit or loss, based on the difference between the consideration received (nil) and the net liability position of Energean Israel Limited as of 13 June 2017 of US$1.5 million.

Details of the cash flows of the discontinued operations which are included in the consolidated statement of cash flows are as follows:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Operating activities	(985)	(83)	193	(334)	—
Investing activities	(2,715)	—	(40,527)	—	—
Financing activities	4,702	9,998	44,854	422	—
Net cash from discontinued operation	**1,002**	**9,915**	**4,520**	**88**	**—**

The major classes of assets and liabilities comprising the operations classified as held for sale are as follows:

Assets	As at 31 December 2016	Liabilities	As at 31 December 2016
Intangible assets	40,528		
Other receivables	66	Other payables	423
Cash and cash equivalents	4,609	Borrowings	44,262
Total assets classified as held for sale	**45,203**	**Total liabilities directly associated with assets classified as held for sale**	**44,685**

9.3 Summarised financial information for Energean Israel Limited at 31 October 2017

On 13 June 2017, Energean Israel Limited was deconsolidated and presented as an investment in associate, in which the Group holds no economic interest. Summarised financial information of the Energean Israel Limited as at 31 October 2017 as per below:

	As at 31 October 2017
Assets	
Non-current assets	54,261
Cash and cash equivalents	10,231
Other current assets	844
Total assets	**65,336**
Liabilities	
Trade and other payables	7,887
Current liabilities	**7,887**
Net assets	**57,449**

	For the ten months ended 31 October 2017
Administrative expenses	(1,869)
Finance income	162
Finance costs	(558)
Net loss	**(2,265)**
Other comprehensive income	—
Total comprehensive income	**(2,265)**

10. Non-controlling interests

10.1 Details of the non-controlling interests

	As at 31 December								
Name of subsidiary	Voting rights			Share of loss			Accumulated balance		
	2016 %	2015 %	2014 %	2016 US$	2015 US$	2014 US$	2016 US$	2015 US$	2014 US$
Kavala Oil S.A.	0.08	0.08	33	(1)	(18)	(3,631)	303	304	(12,906)
Energean International Limited	—	—	—	—	—	—	—	—	—
				(1)	**(18)**	**(3,631)**	**303**	**304**	**(12,906)**

	As at 31 October					
Name of subsidiary	Voting rights		Share of loss		Accumulated balance	
	2017 %	2016 %	2017 US$	2016 US$	2017 US$	2016 US$
Kavala Oil S.A.	0.08	0.08	—	—	294	304
Energean International Limited	—	—	—	—	224,000	—
	—	—	—	—	**224,294**	**304**

Kavala Oil S.A.

At 31 December 2014, Kavala Oil Employees Association held a 33% interest in Kavala Oil S.A. (please refer also to Note 8.1) In the year ended 31 December 2015 the Group exercised their right to convert 8,659,046 preference shares to common shares resulting in the Group holding 99.92% of the voting rights. The conversion of the preferred shares was accounted for as an equity transaction with US$nil cash consideration.

Energean International Limited

On 30 June 2017, as part of the Reorganisation Agreement described in Note 33.4, the loan from Third Point in Energean International Limited (Note 17) was discharged in consideration for the issuance of 224,000 new preference shares in Energean International Limited. The Group derecognised the US$230,761 carrying value of the loan and recognised US$224,000 in equity for the preference shares. The difference of US$6,761 was recognised in other reserves as a capital contribution, as Third Point is an ultimate shareholder of the Group. The US$224,000 equity recognised for the preference shares represents a non-controlling interest in a subsidiary of the Group.

10.2 Dividends

No dividends were paid to the non-controlling interests during the period.

11. Inventories

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Raw materials and supplies	4,840	8,390	4,054	4,119	4,076
Crude oil	9,436	4,452	8,703	4,165	10,608
Total inventories	**14,276**	**12,842**	**12,757**	**8,284**	**14,684**

For the ten months ended 31 October 2017 the Group recognised US$3 (ten months ended 31 October 2016 US$nil, years ended 31 December 2016: US$nil, 2015: US$2,486 and 2014: US$1,024) impairment losses for the write-down of oil and sulphur inventory to net realisable value (Note 27).

The Group's raw materials and supplies consumptions for the ten months ended 31 October 2017 was US$1,414 (ten months ended 31 October 2016: US$1,873, years ended 31 December 2016: US$2,226, 2015: US$1,667, 2014: US$2,623. (Note 23). The Group recognised impairment losses in the ten months ended 31 October 2017 of US$nil (years ended 31 December 2016:of US$403, 2015: US$nil, 2014: US$nil) due to obsolete raw materials and supplies

12. Trade and other receivables

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Financial items					
Trade receivables	268	10,702	2,143	386	437
Receivables from related parties	67	104	3	6	—
Receivables in relation to new exploration areas	—	—	—	581	893
	335	**10,806**	**2,146**	**973**	**1,330**
Non-financial items					
Deposits and prepayments	4,867	4,292	2,799	1,532	4,148
Government subsidies	3,301	2,722	3,077	3,234	3,282
Advance payment to tax authorities against Mandatory Administrative Appeal (Note 34.1)	—	3,246	3,126	3,195	—
Refundable VAT	2,821	3,849	2,591	3,228	1,993
Reimbursement from insurance contracts	392	—	—	—	—
	11,716	**24,915**	**13,739**	**12,162**	**10,753**

Government subsidies mainly relate to grants from Greek Public Body for Employment and Social Inclusion (OAED) to financially support the Kavala Oil S.A. labour cost from manufacturing under the action plan for promoting sustainable employment in underdeveloped or deprived districts of Greece, such as the area of Kavala.

Kavala Oil S.A. have participated in this scheme since July 2010 until subsidies ceased to be in force in January 2016. The subsidies balance still outstanding at ten months ended 31 October 2017 is for the period commencing 1 July 2010 until 31 December 2015.

In December 2015, the Group filed a petition against OAED, and the Greek state itself, seeking the payment of US$2,910 (€2,500). Following several postponements of the hearing initiated by the Greek state, the hearing took place on 14 June 2017 and the final decision to be announced within the year 2018.

The Group is of the view, based on legal advice, that this petition will prevail.

12.1 Neither past due nor impaired balances

Trade balances

The credit quality of trade receivables that are neither past due nor impaired is assessed by reference to historical information about counterparty default rates. The Group for this purpose allocates its neither past due nor impaired trade receivables as follows:

	As at 31 October 2017		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Existing customers with no defaults in past	268	10,702	2,143	386	437
	268	**10,702**	**2,143**	**386**	**437**

In April 2013 the Group entered into an exclusive agreement for sale of oil products to one client, BP Oil International Ltd, which represents the largest part of trade receivables. Trade receivables are collected within a thirty day period, after the bill of lading date. There was no allowance for impairment of receivables during the ten months ended 31 October 2017 (ten months ended 31 October 2016: US$nil, years ended 31 December 2016: US$Nil, 2015: US$Nil, 2014: US$Nil). In accordance with the aforementioned agreement the Group supplies the produced Prinos crude oil to BP Oil International Ltd, until the later of: a) the expiry of the agreement on 31 July 2021 or b) the delivery of ten million barrels. In October 2017, Moodys published an A1 credit rating for BP plc.

The credit quality of non-trade financial receivables that are neither past due nor impaired is assessed by reference to historical information about counterparty default rates. The Group for this purpose allocates its neither past due nor impaired trade receivables as follows:

Non-trade balances	As at 31 October 2017		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Existing debtors with no defaults in past	—	—	—	581	893
Related parties with no defaults in past	67	104	3	6	—
	67	**104**	**3**	**587**	**893**

13. Other non-current asset

	As at 31 October 2017		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Deposits paid to utility organisations for electricity and natural gas used in the oil processing plant.	**575**	**157**	**382**	**801**	**417**

14. Current tax assets

	As at 31 October 2017		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Corporation tax	—	—	92	17	17
	—	**—**	**92**	**17**	**17**

15. Cash and cash equivalents

15.1 Bank deposits and cash and cash equivalents

	As at 31 October 2017		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Cash in hand	24	31	27	20	80
Bank demand deposits	1,327	8,937	7,474	1,442	9,735
Restricted bank deposits	7,312	15,674	5,476	6,776	4,512
	8,663	**24,642**	**12,977**	**8,238**	**14,327**
Less: Non-current deposits	(1,828)	(1,151)	(1,116)	(4,013)	(2,683)
Current portion	**6,835**	**23,491**	**11,861**	**4,225**	**11,644**

The effective interest rate on short-term bank deposits was 0.34% for the ten months ended 31 October 2017 (ten months ended 31 October 2016: 0.34%, years ended 31 December 2016: 0.34%, 2015: 0.35%, 2014: 1.00%).

15.2 Restricted bank deposits

Non-current portion

According to the Greek Law the Group is obligated to plug wells resulting from its own drilling activities. For this purpose, a committee comprising representatives of the three parties involved in the above law; one appointed by the Greek State, a member of the contractor and a third member jointly by the Greek State. The contractor assigns and adjust the amount of environment rehabilitation provision, which is kept in a restricted account, for the fulfilment of the contractor's obligations. For this purpose, the Group maintains respective cash reserves, which amounted to US$396 as of 31 October 2017 (as of 31 October 2016: US$316, as of 31 December 2016: US$305, 2015 US$334, 2014 US$351).

As of 31 December 2015 an amount of US$2,847 (2014: US$2,225), included within non-current restricted bank deposits, concerns cash reserves retained as a bank security pledge in respect of the bank guarantees issued for the Group's investments in Ioannina and Katakolo areas and corresponds to the non-current minimum expenditure obligation for the above areas. The allocation between the current and non-current portion of restricted cash for the aforementioned leases is based on the budget submitted to the Greek Ministry. The corresponding part of restricted cash for the committed budget not included in the following year budget is included in the non-current restricted cash.

As of 31 October 2016 an amount of US$193, (as of 31 December 2016: US$193, 2015: US$193, 2014: US$nil) was maintained in an escrow account for legal and other expenses related to the senior secured loan from its shareholder Third Point. (Note 17). The above amount was released in August 2017 following the loan conversion to preference shares.

As of 31 October 2017 an amount of US$682 (as of 31 October 2016: US$641, as of 31 December 2016: US$619, 2015: US$639, 2014: US$nil) is retained as a bank security pledge for the performance guarantee (amount €587) issued to the Greek Ministry of Environment Energy & Climate Change in respect to the lease agreement for Prinos Area and in accordance to Law 2779/1999.

As of 31 October 2017 a US$3,491 (€3,000) guarantee from Energean Montenegro limited was provided in favour of the state of Montenegro, due to expire on 14 October 2020, relating to the Group's concession and mandatory work programme in Montenegro. The guarantee is secured by a US$3,491 (€3,000) cash deposit and according to the submitted work program of the following year an amount of US$2,740 has been included as the current portion and an amount of US$751 as the non-current portion.

Current portion

As of 31 October 2017 an amount of US$2,601 (as of 31 October 2016: US$4,317, as of 31 December 2016: US$4,131, 2015: US$2,523, 2014: US$1,830) included within current restricted bank deposits, concerns cash reserves retained as a bank security pledge in respect of the bank guarantees issued for the Group's investments in Ioannina and Katakolo areas and corresponds to the current Minimum Expenditure Obligation for the above areas.

As of 31 October 2017 an amount of $116 (as of 31 October 2016: US$219, as of 31 December 2016: US$220) concerns bid guarantee provided to the Greek State as part of the tender process for exploration in Western Greece, related to the (then) ongoing bid for the Aitoloakarnania (since awarded) and Arta Preveza blocks. On 25 May 2017 the Group entered into a lease agreement for the Aitoloakarnania block and shall be asked to replace the existing US$116 million bid guarantee with the performance minimum work programme guarantee upon ratification. The US$113 bid guarantee for the Arta Preveza Block expired on 30 June 2017 as this licence was not awarded to the Group.

16. Share capital

The Company's initial share capital amounted to £50 (US$65), consisting of an issuance of 50,000 ordinary shares of a nominal value of £1.00 (US$1.3) each on 8 May 2017. On 30 June 2017 the Company effected a 100 for 1 share split resulting in 5,000,000 ordinary shares of a nominal value of £0.01 (US$0.013) each.

On 30 June 2017, the Company also became the parent company of the Group through the acquisition of the full share capital of Energean E&P Holdings Limited, in exchange for 65,643,120 £0.01 (US$0.013) shares in the Company issued to the previous shareholders. As of this date, the Company's share capital increased from £50 (US$65) to £706 (US$917). From that point, in the consolidated historical financial information, the share capital became that of Energean Oil & Gas PLC. The previously recognised share capital of US$14,904 thousand and share premium of US$125,851 thousand was eliminated with a corresponding positive merger reserve recognised of US$139,903 thousand. The below tables outline the share capital of the Company as at 31 October 2017 and Energean E&P Holdings Limited as at 31 October 2016 and as at 31 December 2016, 2015 and 2014.

	As at 31 October			
	2017	2017	2016	2016
	Number of shares	US$	Number of shares	US$
Authorised				
Ordinary shares of €1 each			10,940,520	14,904
Ordinary shares of £1 each	**70,643,120**	**917**		

	2017	2017	2016	2016
	Number of shares	US$	Number of shares	US$
Issued and fully paid				
On 1 January	—	14,904	10,940,520	14,904
Group restructuring	65,643,120	(14,052)	—	—
Issuance of shares and share split	5,000,000	65	—	—
At 31 October	**70,643,120**	**917**	**10,940,520**	**14,904**

	As at 31 December					
	2016	2016	2015	2015	2014	2014
	Number of shares	US$	Number of shares	US$	Number of shares	US$
Authorised						
Ordinary shares of €1 each	10,940,520	14,904	10,940,520	14,904	10,940,520	14,904

	2016	2016	2015	2015	2014	2014
	Number of shares	US$	Number of shares	US$	Number of shares	US$
Issued and fully paid						
On 1 January	10,940,520	14,904	10,940,520	14,904	10,940,520	14,904
At 31 December	**10,940,520**	**14,904**	**10,940,520**	**14,904**	**10,940,520**	**14,904**

17. Borrowings

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Current borrowings					
Loans from shareholders	—	10,022	21,130	—	—
	—	**10,022**	**21,130**	**—**	**—**
Non-current borrowings					
Bank loans	77,880	59,943	60,253	—	—
Other loans	1,306	1,228	1,182	1,221	1,362
Loans from shareholders	—	207,282	193,683	186,181	116,568
	79,186	**268,453**	**255,118**	**187,402**	**117,930**
Total borrowings	**79,186**	**278,475**	**276,248**	**187,402**	**117,930**

Loans in the consolidated statement of financial position are presented net of amortized cost. Please see Note 33.3 for loans from related parties.

17.1 Maturity of non-current borrowings

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Between one to two years	1,306	11,250	—	—	—
Between two and five years	77,880	267,225	255,118	187,402	117,930
	79,186	**278,475**	**255,118**	**187,402**	**117,930**

Loans from shareholders

In 2014, the Group received a senior secured loan from its shareholder Third Point amounting to US$125,000 in order for the Group to fund the ongoing drilling campaign. The loan was issued at a discount of 90% of face value, had a 5 year tenor, paid a fixed interest rate of 9.5% until 31 December 2016 and paid a fixed interest rate of 15.0% for the remaining tenor. In 2015, the loan was amended to increase the amount to US$179,653. On 30 June 2017, as part of the Reorganisation Agreement as described in Note 33.4, the loan was discharged in consideration for the issuance of 224,000 new preference shares in Energean International Limited. The Group derecognised the loan and recognised the preference shares as equity. The equity recognised represents a non-controlling interest in a subsidiary of the Group.

Bank loans

EBRD Senior Facility

In May 2016, the Group signed a Senior Facility Agreement with the EBRD, subsequently amended on 12 July 2016, for a US$75 million borrowing base facility to fund Group's development programme in Prinos, Prinos North and Epsilon fields. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission.

EBRD Subordinated Facility

In July 2016, the Group signed a EBRD Subordinated Facility Agreement, a subordinated loan agreement with the EBRD, subsequently amended on 8 March 2017, for a US$20 million facility to fund the Group's exploration activities. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission and an EBITDA participation amount of up to 3.5% of EBITDA (if EBITDA is positive) depending on the amount of the facility drawn.

Other loans

On 26 March 2013, Cyprus Popular Bank Public Company Ltd (Greek branch) which Kavala Oil S.A. transacted with on European Emission Allowances credits (hereby referred to as "EUAs") during previous years, was sold to Piraeus Bank. Since then and as of the date of these consolidated historical financial information, there has not been any written or oral communication with the Bank. Therefore, the Group has decided to further investigate, seeking legal advice on how to deal with this matter. The amount of the liability as of 31 October 2017 is US$1,306 (as of 31 October 2016 US$1,228, as of 31 December 2016: US$1,182, 2015: US$1,221, 2014: US$1,362). These loans are non-interest bearing and then due on demand.

17.2 Securities pledged

Bank loans

The bank loans are secured as follows:

- First ranking and second ranking share pledge agreement over Energean Oil & Gas S.A. shares
- First ranking and second ranking share pledge agreement over the Kavala Oil S.A.'s shares
- First ranking and second ranking contracts pledge and assignment over material agreements related to Prinos drilling
- First ranking and second ranking insurances pledge assignment
- First ranking and second ranking accounts pledge and assignment
- First ranking and second ranking ship mortgage over the 'Energean Force' drilling rig

17.3 The weighted average effective interest rates were as follows:

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Bank loans	7.08%	6.98%	6.96%	—	—
Loans from shareholders (Note 33)	15.42%	15.68%	15.39%	15.19%	12.33%

18. Net deferred tax (liability)/ asset

The deferred taxation movement is as follows:

Deferred tax (liabilities)/assets	Property, plant and equipment	Trade and other receivables	Inventory	Tax losses	Staff leaving indemnities	Accrued expenses and other short-term liabilities	Total
At 1 January 2014	**(38,864)**	**—**	**878**	**40,121**	**578**	**373**	**3,086**
Increase / (decrease) for the year through:							
Profit or loss	(235)	2,582	(495)	(9,233)	9	110	(7,262)
Foreign exchange impact	4,724	(222)	(51)	(4,006)	(19)	(115)	311
31 December 2014	**(34,375)**	**2,360**	**332**	**26,882**	**568**	**368**	**(3,865)**
Increase / (decrease) for the year through:							
Profit or loss (Note 31)	(13,315)	4,436	(18)	19,069	163	274	10,609
Foreign exchange impact	3,828	(191)	(70)	(3,134)	(66)	(173)	194
31 December 2015	**(43,862)**	**6,605**	**244**	**42,817**	**665**	**469**	**6,938**
Increase / (decrease) for the year through:							
Profit or loss (Note 31)	(9,319)	4,024	692	15,578	142	400	11,517
Other comprehensive income	—	—	—	—	41	—	41
Foreign exchange impact	2,081	(402)	(287)	(2,099)	(66)	(34)	(807)
31 December 2016	**(51,100)**	**10,227**	**649**	**56,296**	**782**	**835**	**17,689**
At 1 January 2016	**(43,862)**	**6,605**	**244**	**42,817**	**665**	**469**	**6,938**
Increase / (decrease) for the period through:							
Profit or loss (Note 31)	(13,259)	1,296	506	18,418	51	54	7,066
Other comprehensive income	—	—	—	—	36	—	36
Foreign exchange impact	256	227	(221)	(103)	(96)	(192)	(129)
31 October 2016 (unaudited)	**(56,865)**	**8,128**	**529**	**61,132**	**656**	**331**	**13,911**
At 1 January 2017	**(51,100)**	**10,227**	**649**	**56,296**	**782**	**835**	**17,689**
Increase / (decrease) for the period through:							
Profit or loss (Note 31)	(7,349)	(12,223)	(308)	13,341	57	218	(6,264)
Foreign exchange impact	(5,603)	597	61	6,376	(18)	191	1,604
31 October 2017	**(64,052)**	**(1,399)**	**402**	**76,013**	**821**	**1,244**	**13,029**

At 31 October 2017 the Group has unused tax losses of US$304,051 (as of 31 October 2016: US$244,528, as of 31 December 2016: US$225,184, 2015: US$171,268, 2014: US$107,528) available to offset against future profits. A deferred tax asset has been recognised as of 31 October 2017 in respect of US$76,013 (as of 31 October 2016: US$61,132, as of 31 December 2016: US$56,296, 2015: US$42,817, 2014: US$26,882) of such tax losses.

Tax losses can be utilised to offset taxable profits for a period of time that is dictated by the tax legislation of each country. Tax losses in relation to the companies operating under the licence obtained by Greek Law can be utilsed to offset taxable profits up to the termination of Prinos exploitation area. The above carried forward unused tax losses arise almost exclusively from the Prinos Area. Tax losses incurred under the Prinos licence (Law2779/1999) can be utilised to offset taxable profits up to the termination of Prinos exploitation area.

According to the Ioannina and Katakolo lease agreements the losses incurred in respect of a particular exploitation area prior to the commencement of any exploitable production shall be carried forward without any restrictions for such period. From the commencement of any exploitable production and thereafter, the general income tax provisions shall apply in relation to the carrying forward of losses (currently 5 years).

The Group expects that there will be sufficient taxable profit in the following years and that deferred tax assets, recognised in the historical financial information of the Group, will be recovered.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries and associates, and interest in joint ventures, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. The Group has no unrecognised deferred tax liabilities for taxable temporary differences arising on its investments in subsidiaries and associates, and interest in joint ventures.

19. Provisions for liabilities

	Retirement benefits (Note 20)	Provision for environment rehabilitation	Total
At 1 January 2014	2,311	937	3,248
Charged / (credited) to profit or loss*	224	(37)	187
Actuarial losses	242	—	242
Benefits paid	(363)	—	(363)
Discount unwinding*	71	63	134
Exchange differences	(292)	(112)	(404)
At 1 January 2015	**2,193**	**851**	**3,044**
Charged to profit or loss*	451	116	567
Actuarial losses	9	—	9
Benefits paid	(344)	—	(344)
Discount unwinding*	35	76	111
Exchange differences	(229)	(87)	(316)
At 1 January 2016	**2,115**	**956**	**3,071**
Charged to profit or loss*	296	374	670
Actuarial losses	148	—	148
Utilised amount	(89)	—	(89)
Discount unwinding*	39	95	134
Increase in asset value	—	910	910
Exchange differences	(84)	(95)	(179)
At 31 December 2016	**2,425**	**2,240**	**4,665**
At 1 January 2016	**2,115**	**956**	**3,071**
Charged to profit or loss*	202	—	202
Actuarial losses	130	—	130
Utilised amount	(31)	—	(31)
Discount unwinding*	33	95	128
Increase in asset value	—	483	483
Exchange differences	5	4	9
At 31 October 2016 (unaudited)	**2,454**	**1,538**	**3,992**
At 1 January 2017	**2,425**	**2,240**	**4,665**
Charged to profit or loss*	211	319	530
Actuarial losses	—	—	—
Utilised amount	(40)	—	(40)
Discount unwinding*	34	206	240
Increase in asset value	—	853	853
Exchange differences	260	241	501
At 31 October 2017	**2,890**	**3,859**	**6,749**

* Note that for purposes of the provision for environmental rehabilitation, charged to profit and loss and discount unwinding are both charged to the profit and loss.

19.1 Provision for environment rehabilitation

According to article 27 of Greek Law 2779/1999, the Group is obliged to plug only the wells drilled pursuant to its own drilling activities. For this purpose, a committee was formed comprised of representatives of the three parties involved in the above law, one appointed by the Greek State, a member of the contractor and a third member jointly by the Greek State and the contractor. The committee assigns and adjust the amount of environment rehabilitation expenditure, which should be kept in restricted accounts, for the fulfilment of the Contractor's obligations.

The last meeting of the Committee in 2004 defined the amount of obligation as US$310 (€235) which has been adjusted to US$ at each balance sheet date (as of 31 October 2017: US$273, 31 October 2016: US$257, as of 31 December 2016: US$247, 2015: US$256, 2014: US$285). This amount was included in the cost of wells, and an equivalent provision for environment rehabilitation was established.

In excess of this obligation, the Group recognises an estimated restoration amount for each well drilled a restoration obligation in accordance with IAS 37 '*Provisions, Contingent Liabilities and Contingent Asset*'. The amount recognised as a provision is the present value of the expenditure estimate required to settle the obligation at each balance sheet date, discounted at 6.18% until 2032. The provision is reviewed and adjusted at each balance sheet date as necessary.

19.2 Legal claims

Tax

During the year ended 31 December 2014, the statutory tax audit of Kavala Oil S.A. for the years 2006 – 2011 was finalised and the official Tax Report was issued by the Greek tax authorities for tax and transfer pricing penalties amounting to US$6,475 (€5,564). On 22 April 2015, Kavala Oil S.A. has proceeded in executing its Mandatory Administrative Appeal before the Dispute Resolution Directorate of the Greek Ministry of Finance against certain tax assessment notices.

The Group were required to make a prepayment of 50% of the value of the total exposure thus a total amount of US$3,238 (€2,782) was paid by Kavala Oil S.A. during 2015. In the years ended 31 December 2016 and 2015 this amount was presented in Trade and other receivables (see Note 12) as an advanced payment to Greek tax authorities against. In 2017, the amount was no longer recorded as an advance payment due to a provision being recognised in full for the tax and transfer pricing penalties, as fully explained later in this note. In the years ended 31 December 2016 and 2015 The Company had not recorded a provision for the initial tax and transfer pricing penalty.

The appeals were rejected implicitly by the Dispute Resolution Directorate of the Greek Ministry of Finance. Against the decisions of the Dispute Resolution Directorate, Kavala Oil S.A. filed on 8 October 2015 equal number of appeals before the Athens Administrative Court of Appeal. The discussion of these actions took place in February 2017 and the final decision is expected by 31 March 2018.

Developments in the tax audit framework in Greece, and specifically the repeal of the 18 month period under which an unqualified tax certificate issued by the statutory auditors to audited companies was considered to be final and the respective tax year to be considered as "finalised", resulted in a change in attitude of many taxpayers, during the period ended 31 October 2017, in respect to the approach followed with unaudited tax years.

In addition, the five-year statute of limitation for the unaudited year of 2012 ends by the end of 2018. As of 31 October 2017, the Company has not received a tax audit request for the most recent non-prescribed unaudited year which in the case of Kavala Oil S.A. is 2012.

Kavala Oil S.A.'s court appeal against the transfer pricing penalties as well as the adjustment of the tax losses of the company is still pending and in the case that a tax audit request is submitted to the company before the issuance of the court decision, it is likely that the tax auditors will follow the same approach as their predecessors and adjust the tax losses of the company accordingly.

Following the developments that took place in this period, the Company recognised a provision for its unaudited tax years 2012 – 2016 of US$4,055. This takes into consideration the outcome of the tax audit of the Company's transfer pricing policies finalised for fiscal year 2011. This amount corresponds to corporate income tax amount of US$2,285 (Note 31) plus penalties and interest of US$1,771 (Note 27).

The Company has also recorded a provision of US$6,839 for fiscal years 2006 – 2011 it is currently appealing. The amount differs from the initial assessment in the Tax Report due to additional interest and penalties accruing during the appeals process. The decision of the court is expected to be issued no sooner than the first quarter of 2018,if the decision is not in favour of the company, this amount is payable in two equal monthly instalments. In such case, the Group's intention is to submit an appeal at the higher level court (Council of State). US$3,725 of the US$6,839 has been already paid as pre-payment in order the company to submit an administrative appeal. The total provision amounts for transfer pricing and income tax penalties and additional taxes of US$8,610 are included in other expenses (Note 27) and taxation expenses amount of US$2,285 in taxation (expense) / income (Note 31). The total payable amount under the above provision, out of already paid amount of US$3,725, is included in current liabilities under "Provisions for liabilities" and "Current tax liabilities" in the consolidated statement of financial position since the Company estimates the final decision will not be announced until 31 March 2018.

The company expects to prevail in its mandatory administrative appeal, however it cannot be assured that penalties will not be imposed.

Other

The Plaintiff, a State Company entrusted with the Operation of the Electricity Transmission System in Greece ("ADMIE"), commenced this claim against Kavala Oil SA in November 2014 seeking payments of an amount EUR 376 as utilities charges of the time period 2009 – 2011. ADMIE alleges that Kavala Oil, as owner of a Power Plant within the onshore facilities in Kavala and as the operator of this power plant exclusively for industrial own use, is subject to these charges -as any ordinary energy consumer- provided by Law (Greek Energy Law Acts No 2773/1999, 4067/2012 & 4001/2011) and the Regulation of electricity distribution and transmission charges, approved by the Greek Energy Regulatory Commission ("RAE") in 2008 and 2009 ("Charge Regulation 2008", "Charge Regulation 2009", "CHR 2008 & 2009").

It must be noted that RAEs' CHR 2008 & 2009 have been contested (by social organisations and other entities of consumers) before the Greek Supreme Administrative Court (Council of State) and due to constitutional illegality annulled. Thus, the abovementioned Law Act No 4001/2011 reintroduced provisions similar to these of RAE's CHR 2008 & 2009.

By the Decision of the Court of Appeal No 91/2017 the Group is ordered to the payment of Euros 376 (plus interest from the claim filing date, 30 December 2014). Thus the Group proceed with a provision amount US$405 which is included in "Other expenses". Effective October 2017, the Group started the repayment of the awarded amount in ten equal instalments of Euros 49.7 each, bearing no interest, out of which the 1st was paid in November 2017 and the 10th and last on shall be paid in August 2018. The Group reserves all rights against ADMIE based on the outcome of the case brought before the Supreme Court.

Allocated as:

	As at 31 October		As at 31 December		
	2017	2016	2016	2015	2014
Provisions to be used after more than twelve months	6,749	3,992	4,665	3,071	3,044
Provisions to be used within twelve months	7,697	—	—	—	—
	14,446	**3,992**	**4,665**	**3,071**	**3,044**

20. Retirement benefits obligation

The Group provides retirement benefits in the form of lump sum amounts based on an unfunded fixed benefit retirement plan to its employees. The Group's policy is to carry out an independent actuarial valuation every three years of the liabilities with regard to the retirement benefit plan.

According to the plan, a certain percentage of the current salary is converted into a pension component each year until retirement. Pensions under this scheme are paid out when a beneficiary has reached the age of 65. Eligible employees are required to contribute 2% of this pensionable salary. The pension payments are also linked to the Greek consumer price index (CPI) in Euro.

In accordance with the provisions of Greek labour law, employees are entitled to compensation in case of dismissal or retirement. The amount of compensation varies depending on salary, years of service and the manner of termination (dismissal or retirement). Employees who resign are not entitled to compensation. The compensation payable in case of retirement is equal to 40% of the compensation which would be payable in case of unjustified dismissal. These plans are not funded and are defined benefit plans in accordance with IAS 19. The Greek subsidiaries charge the accrued benefits in each period with a corresponding increase in the relative actuarial liability. The payments made to retirees in every period are charged against this liability. The liabilities of the Group arising from the obligation to pay termination indemnities are determined through actuarial studies, conducted by independent actuaries.

20.1 Provision for retirement benefits

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Defined benefit obligation	2,890	2,454	2,425	2,115	2,193
Provision for retirement benefits recognised	**2,890**	**2,454**	**2,425**	**2,115**	**2,193**
Allocated as:					
Non-current portion	2,890	2,454	2,425	2,115	2,193
	2,890	**2,454**	**2,425**	**2,115**	**2,193**

20.2 Defined benefit obligation

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
At 1 January	2,425	2,115	2,115	2,193	2,311
Current service cost	211	202	253	312	246
Interest cost	34	33	39	35	71
Extra payments or expenses	—	—	43	139	(22)
Actuarial losses—from changes in financial assumptions	—	130	148	9	242
Benefits paid	(40)	(31)	(89)	(344)	(363)
Exchange differences	260	5	(84)	(229)	(292)
Total	**2,890**	**2,454**	**2,425**	**2,115**	**2,193**

The average duration of the defined benefit obligation at 31 October 2017 is 25 years (ten months ended 31 October 2016: 25 years, years ended 31 December 2016: 25 years 2015: 25 years, 2014: 24 years).

As of 31 October 2017, based on historical data, the Group expects benefits of approximately US$70 to be paid for 2018.

20.3 Impact to total comprehensive income

Amounts recognised in profit or loss:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Current service cost	211	202	253	312	246
Interest cost	34	33	41	36	72
Extra payments or expenses / (income)	—	—	43	139	(22)
Total expense	**245**	**235**	**337**	**487**	**296**
Amounts recognised in other comprehensive income:					
Actuarial losses—from changes in financial assumptions	—	130	148	9	242
Total remeasurements	**—**	**130**	**148**	**9**	**242**

20.4 Actuarial assumptions and risks

The most recent actuarial valuation was made as of 31 October 2017 and it was based on the following key assumptions:

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Discount rate	**1.50%**	**1.50%**	**1.50%**	1.80%	1.80%
Expected rate of salary increases	**3.59%**	**3.59%**	**3.59%**	3.84%	3.84%
Average life expectancy over retirement age	**24.57 years**	**24.57 years**	**24.57 years**	28.93 years	28.93 years
Inflation rate	**1.75%**	**1.75%**	**1.75%**	2.00%	2.00%

Sensitivity analysis

The sensitivity analysis below shows the impact on the defined benefit obligation of changing each assumption while not changing all other assumptions. This analysis may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

	As at 31 October		As at 31 December		
Effect of + 0.5% change in defined benefit obligation	2017	2016 (unaudited)	2016	2015	2014
Discount rate	+ 9.0%	+ 9.0%	+ 9.0%	+ 5.5%	+ 5.5%
Expected rate of salary increases	+ 14.0%	+ 14.0%	+ 14.0%	+ 5.0%	+ 5.0%
Effect of - 0.5% change in defined benefit obligation					
Discount rate	- 9.0%	- 9.0%	- 9.0%	- 5.5%	- 5.5%
Expected rate of salary increases	- 14.0%	- 14.0%	- 14.0%	- 5.0%	- 5.0%

The amounts presented reflect the percentage increase / (decrease) in the given assumption that is required to impact the defined benefit obligation by +/- 0.5%, while holding all other assumptions constant.

The plan exposes the Group to actuarial risks such as interest rate risk, longevity changes and inflation risk.

Interest rate risk

The present value of the defined benefit liability is calculated using a discount rate determined by reference to market yields of high quality corporate bonds. The estimated term of the bonds is consistent with the estimated term of the defined benefit obligation and it is denominated in Euro. A decrease in market yield on high quality corporate bonds will increase the Group's defined benefit liability.

Longevity of members

The Group is required to provide benefits for life for the members of the plan. Any increase in the life expectancy of the members will increase the defined benefit liability.

Inflation risk

A significant proportion of the defined benefit liability is linked to inflation. An increase in the inflation rate will increase the Group's defined benefit liability.

21. Trade and other payables

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Financial items					
Trade payables	36,776	18,847	18,976	20,743	12,589
Accrued expenses	13,816	11,811	5,424	3,914	1,868
Other creditors	1,384	815	834	—	—
Other finance costs accrued	—	—	—	297	346
Accrued fees related to lease agreements	—	—	—	—	914
Staff costs accrued	797	617	1,313	1,317	1,294
Personnel insurance	—	—	—	—	260
	52,773	**32,090**	**26,547**	**26,271**	**17,271**
Non-financial items					
Social insurance and other taxes	4,389	4,828	5,272	4,850	6,645
Total	**4,389**	**4,828**	**5,272**	**4,850**	**6,645**
Less non-current payables	**(2,555)**	**(2,954)**	**(2,737)**	(3,299)	—
Current portion	**54,607**	**33,964**	**29,082**	**27,822**	**23,916**

As of 31 October 2017 the amount of US$3,093 (as of 31 October 2016: US$3,559, as of 31 December 2016: US$3,355 2015: US$3,937 2014: US$Nil) relates to Kavala Oil's social security liabilities from prior periods (years 2011 and 2012), which are included in a settlement schedule where this is repaid in 100 equal-amounted instalments, as per the provisions of Greek Law. The non-current payables include amount US$2,555 relates to the non-current portion of the social security's liabilities.

22. Revenue

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Crude oil sales	36,565	30,566	38,843	25,141	40,255
Sales of scrap	15	25	25	8	—
Rendering of services	1,074	—	—	11	359
Petroleum products sales	771	1,133	1,389	1,115	958
Gain/(loss) on forward transactions	—	(537)	(533)	2,159	672
Total sales revenue	**38,425**	**31,187**	**39,724**	**28,434**	**42,244**

For the ten months ended 31 October 2017, the amount of US$1,074 included in "Revenue from rendering of services" related to services provided by Energean International Limited under the 19 December 2016 Services Agreement to Energean Israel Limited (please refer also to Note 33).

For the years ended 31 December 2015 and 31 December 2014 the amounts of US$11 and US$359 correspondingly included in "Revenue from rendering of services" related to services provided by Energean International Limited under the 26 November 2014 Services Agreement to Energean Israel Limited.

23. Cost of sales

	For the ten months ended 31 October		For the year ended 31 December		
Cost of Oil Sales	**2017**	**2016 (unaudited)**	**2016**	**2015**	**2014**
Opening inventory	9,154	4,265	4,074	9,590	5,075
Closing inventory	(9,008)	(8,548)	(9,044)	(6,494)	(12,506)
	146	(4,283)	(4,970)	3,096	(7,431)
Direct costs					
Staff costs (Note 29)	10,628	9,900	11,609	10,841	14,915
Subcontracted work	555	545	670	831	1,719
Electricity and fuel	4,854	5,161	6,014	5,711	9,474
Machinery repairs and maintenance	2,160	1,778	2,046	1,430	1,978
Insurance	1,081	767	998	969	985
Sundry expenses	306	321	410	291	592
Consumptions	1,414	1,873	2,226	1,667	2,623
Depreciation (Note 6)	14,480	15,261	21,218	7,292	7,424
Royalties	120	251	330	—	—
	35,598	**35,857**	**45,521**	**29,032**	**39,710**
Total Cost of Oil Sales	**35,744**	**31,574**	**40,551**	**32,128**	**32,279**

	For the ten months ended 31 October		For the year ended 31 December		
Cost of Services	**2017**	**2016 (unaudited)**	**2016**	**2015**	**2014**
Staff costs (Note 29)	531	—	—	—	—
Other professional fees	62	—	—	—	—
Other expenses	26	—	—	—	—
Total Cost of Services	**619**	**—**	**—**	**—**	**—**
Total Cost of Sales	**36,363**	**31,574**	**40,551**	**32,128**	**32,279**

24. Exploration and evaluation expenses

	For the ten months ended 31 October		For the year ended 31 December		
	2017	**2016 (unaudited)**	**2016**	**2015**	**2014**
Staff costs (Note 29)	195	941	1,133	—	—
Write-off of exploration and evaluation costs (Note 7)	6,646	—	—	—	—
Impairment of exploration and evaluation costs	—	—	—	61	199
Third party fees	209	175	—	191	109
Total	**7,050**	**1,116**	**1,133**	**252**	**308**

25. Administration expenses

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Staff costs (Note 29)	1,936	1,552	1,989	2,828	4,010
Telecommunication and other office expenses	345	142	153	64	107
Operating leases	299	224	251	278	321
Licences and taxes	29	26	29	162	55
Repairs and maintenance	191	—	1	47	9
Audit fees for statutory audit	148	84	92	93	178
Auditors' fees for other assurance services	59	69	69	17	65
Auditors' fees for tax services	—	18	21	9	17
Accounting fees	12	9	12	16	—
Legal fees	222	218	330	352	332
Other professional fees	248	283	301	328	341
Overseas travelling	238	164	203	116	164
Corporate social responsibility	19	31	25	58	65
Amortisation of intangibles (Note 7)	177	125	144	153	95
Depreciation property, plant and equipment (Note 6)	274	153	137	136	204
Other administration expenses	142	207	377	131	278
Total general and administration expenses	**4,339**	**3,305**	**4,134**	**4,788**	**6,241**

26. Selling and distribution expenses

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Staff costs (Note 29)	138	137	163	151	110
Advertising	166	127	131	110	142
Sundry expenses	9	3	42	47	46
Total selling and distribution expenses	**313**	**267**	**336**	**308**	**298**

27. Other expenses

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Other taxes	40	25	7	283	1,480
Other expenses	527	121	754	252	277
Other staff costs	—	—	—	—	51
Provision for litigation expenses (Note 19.2)	8,688	—	—	—	—
Provision for bad debts	401	—	—	—	—
Loss from disposal of property, plant and equipment (Note 6)	—	1,589	1,577	—	—
Impairment loss on property, plant and equipment (Note 6)	111	—	1,947	40	4,650
Impairment loss on inventory	3	—	403	2,486	1,024
Total other expenses	**9,770**	**1,735**	**4,688**	**3,061**	**7,482**

Provision for litigation expenses amounting to US$6,839 relates to transfer pricing penalties, amount of US$1,771 relates to income tax penalties (please refer to Note 19.2)

28. Other income

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Reversal of prior period provision	629	558	248	265	759
Write-off of portion of loans due to Piraeus Bank	—	—	—	—	24,927
Gain from disposal of subsidiary (Note 9)	1,540	—	—	—	—
Technical consultancy fees	—	—	—	—	506
2,169	**558**	**248**	**265**	**26,192**	

Reversal of prior period provision concerns mainly reversals of prior period provisions related to employee vacation leave and other, as well as previous period energy cost credits.

In April 2014, the Group and its subsidiary Energean Oil & Gas S.A. signed an agreement with Piraeus Bank for a discounted cash settlement of the amount of US$56,000 for all outstanding loans of the Energean Group as of 31 December 2013. The result of the write-off was to recognise the remaining balance as an income for the Group.

29. Staff costs

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Wages and salaries	13,973	12,167	13,950	13,704	14,685
Directors' remuneration	1,512	927	1,720	1,560	2,045
Social insurance costs and other funds	3,333	2,750	3,547	3,487	3,949
Other staff costs	920	957	1,167	720	1,251
Expenses related to defined benefits plan (Note 20)	211	202	296	451	224
Payroll subsidies	(52)	—	(13)	(534)	(650)
Payroll Cost capitalised in oil and gas assets and Exploration and evaluation costs	(6,469)	(4,382)	(5,773)	(5,568)	(2,416)
Total payroll cost	**13,428**	**12,621**	**14,894**	**13,820**	**19,088**
Staff cost included in:					
Cost of sales	11,159	9,900	11,609	10,841	14,915
Exploration and evaluation costs	195	941	1,133	—	
Administration expenses	1,936	1,552	1,989	2,828	4,010
Selling and distribution expenses	138	137	163	151	110
Other expenses	—	91	—	—	53
Payroll cost expensed	**13,428**	**12,621**	**14,894**	**13,820**	**19,088**
Average number of employees (excluding executive Directors):	393	381	379	344	312

30. Finance income and costs

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Finance income					
Interest income	14	323	327	91	166
	14	323	327	91	166
Finance costs:					
Interest bearing loans and borrowings	4,665	2,046	2,407	—	790
Bank overdrafts	—	—	—	—	1,067
Amortisation of related parties' loan interest and issuance fees (Note 33)	16,068	21,101	28,652	22,391	12,456
Unwinding of discount on provisions	206	95	93	58	69
Interest expenses of pension benefit obligation	34	34	39	35	71
Fees for Group funding purposes	469	891	610	547	3,974
Risk management and other hedging costs	—	—	—	—	85
Other bank charges	746	685	1,502	660	605
Capitalisation of borrowing costs to assets	(1,056)	(3,855)	(3,992)	(3,553)	(834)
Total finance costs	**21,132**	**20,997**	**29,311**	**20,138**	**18,283**
Net Finance Costs	**(21,118)**	**(20,674)**	**(28,984)**	**(20,047)**	**(18,117)**

Finance income represents interest income earned on cash at banks and short-term deposits.

31. Taxation (expense) / income

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Corporation tax—current year	(227)	—	—	(15)	(55)
Corporation tax—prior years	(2,285)	—	—	(13)	—
Deferred tax (Note 18)	(6,264)	7,066	11,517	10,609	(7,262)
Total taxation (expense)/income	**(8,776)**	**7,066**	**11,517**	**10,581**	**(7,317)**

Taxation—Cyprus

The Group is subject to corporation tax on its taxable profits at the rate of 12.5%. Any capital gains are taxed at the rate of 20%.

Under certain conditions interest is subject either to corporation tax or to defence contribution. The relevant corporation tax rate for the year is 12.5% and the defence contribution rate is 30%.

Companies in Cyprus which do not distribute 70% of their profits after tax, as defined by the relevant tax law, within two years after the end of the relevant tax year, will be deemed to have distributed as dividends 70% of these profits. Special contribution for defence at 17% will be payable on such deemed dividends to the extent that the shareholders (companies and individuals) are both tax resident and also domiciled in Cyprus. The amount of deemed distribution is reduced by any actual dividends paid out of the profits of the relevant year at any time. This special contribution for defence is payable for the account of the shareholders. Given the current tax position of the Group's companies in Cyprus, these deemed distribution rules are not applicable.

Taxation—Greece

The nominal tax rates applicable to Energean are exclusively governed per each contract area by the provisions of the lease agreements ratified by Laws 2779/1999 (Prinos), 4298/2014 (Katakolo) and 4300/2014 (Ioannina).

The applicable tax rate according to aforementioned agreements for the ten month period ended 31 October 2017 is 25% (ten months ended 31 October 2016: 25%, years ended 31 December 2016, 2015, 2014: 25%).

On 12 July 2017 a tax audit order was issued by the Greek tax authorities in respect of FY12 for Energean Oil & Gas SA, the request of information commenced on 15 January 2018. For FY12, Energean Oil & Gas S.A, was audited by, Grant Thornton, in accordance with article 82 of Greek Law 2238/1994 and received an unqualified tax certificate. On this basis should any tax liabilities arise from the audit, they are not expected to have a material effect on the historical financial information.

The nominal tax rate of Kavala Oil S.A. for the period ended 31 October 2017 is 29% (ten months ended 31 October 2016: 29%, years ended 31 December 2016: 26% 2015: 26%, 2014: 24%).

The tax on the Group's results before tax differs from the theoretical amount that would arise using the applicable tax rates as follows:

Reconciliation to Group tax charge:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Profit/(loss) before tax	**11,968**	**(26,535)**	**(50,126)**	**(44,067)**	**(6,584)**
Tax calculated at the applicable tax rates	(2,992)	6,634	12,532	11,017	1,646
Impact of different tax rates	17	(77)	(12)	(92)	(276)
Reassessment of recognised deferred tax asset in the current period	—	—	—	—	(9,362)
Permanent differences	(3,516)	547	(1,076)	(531)	532
Other adjustments	—	(38)	73	174	143
Prior year tax	(2,285)	—	—	13	—
Taxation (expense) / income	**(8,776)**	**7,066**	**11,517**	**10,581**	**(7,317)**

32. Earnings per share

The earnings per share has been calculated by dividing the net profit or loss for the period by the weighted average number of shares outstanding during the periods ended 31 October 2017 and 2016 and 31 December, 2016, 2015, and 2014. There were no potentially dilutive instruments outstanding during any period, therefore the basic and diluted earnings per common share were equal.

In accordance with IAS 33 *'Earnings per share*', the comparative weighted average number of shares was restated to apply the number of shares which arose from the Group reconstructing described in Note 16.

From continuing and discontinued operations

The calculation of the basic and diluted earnings / (loss) per share is based on the following data:

Profit / (loss)

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Gain / (loss) from continuing operations attributable to owners of the parent	4,604	(19,361)	(38,379)	(33,402)	(10,166)
Loss from discontinued operations	(1,403)	(108)	(229)	(66)	(104)

Number of shares

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Weighted average number of ordinary shares in issue during the year (prior to the Group restructure)	10,940,520	10,940,520	10,940,520	10,940,520	10,940,520
Weighted average number of ordinary shares in issue during the year (post the Group restructure)	70,643,120	70,643,120	70,643,120	70,643,120	70,643,120

From continuing operations

	Basic & Diluted		Basic & Diluted		
	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Total earnings/(loss) from continuing operation per share (prior to the Group restructure)	**$0.42**	**($1.77)**	**($3.51)**	**($3.05)**	**($0.93)**
Total earnings/(loss) from continuing operation per share (post the Group restructure)	**$0.07**	**($0.27)**	**($0.54)**	**($0.47)**	**($0.14)**

From discontinued operations

	Basic & Diluted		Basic & Diluted		
	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Total loss from discontinued operations per share (prior to the Group restructure)	**($0.13)**	**($0.01)**	**($0.02)**	**($0.01)**	**($0.01)**
Total loss from discontinued operations per share (post the Group restructure)	**($0.02)**	**($0.00)**	**($0.00)**	**($0.00)**	**($0.00)**

33. Related parties

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note. Transactions between the Group with its associates and other related parties are disclosed below.

The Group is not controlled by any legal entity or physical person, including its shareholders.

Adobelero Holdings Co Ltd. is a beneficially owned holding company controlled by Panos Benos, the CFO of the Group. Growthy Holdings Co Ltd is a beneficially owned holding company controlled by Mathios Rigas, the CEO of the Group. Oil Co Investments Limited is beneficially owned and controlled by Efstathios Topouzoglou, a Non-Executive Director of the Group. The nature of the Group's transactions with the above related parties is mainly financing activities.

Seven Maritime Company (Seven Marine) is a related party company controlled by Efstathios Topouzoglou. Seven Marine owns the offshore supply ships Valiant Energy and Energean Wave which supports the Group's investment program in northern Greece.

Third Point Hellenic Recovery (Lux) S.A.R.L is a US based institutional investor that has historically supported the Group through debt funding and remains one of the Group's largest shareholders.

33.1 Trading transactions

During the year, Group companies entered into the following transactions with related parties who are not members of the Group:

Sale of assets

In May 2016, the subsidiary Energean Oil & Gas S.A. sold its Greek flagged supply vessel named Valiant Energy for the amount of US$2,698. The net book value of the vessel at the time of the sale was US$4,275 and therefore a loss of US$1,577 was recognised in 2016. Later in May 2016, the subsidiary leased back the vessel through a time charter agreement (an operating lease agreement) with Seven Marine.

Sale of technical services

A Technical Services Agreement dated 19 December 2016 was signed between Energean International Limited and Energean Israel Limited for the provision of project advisory, technical and commercial consulting services between the two companies.

Services are compensated based on a daily rates negotiated on an arms-length basis.

		For the ten months ended 31 October		For the year ended 31 December		
	Nature of transactions	2017	2016 (unaudited)	2016	2015	2014
Other related party (under common control)	Sale of vessel	—	2,932	2,911	—	—
Energean Israel Ltd	Technical services	1,074	—	—	—	—
		1,074	2,932	2,911	—	—

Purchase of goods or services

		For the ten months ended 31 October		For the year ended 31 December		
	Nature of transactions	2017	2016 (unaudited)	2016	2015	2014
Key management	Financial advisory services	—	341	512	75	1,134
Other related party "Seven Marine"	Vessel leasing	5,360	1,405	2,482	—	—
Third Point Hellenic Recovery Fund L.P.	Finance cost	16,068	21,101	28,652	22,391	12,456
Growthy Holdings CO	Finance cost	43	10	35	—	—
Oilco Investments Limited	Finance cost	43	10	35	—	—
Adobelero Holdings CO	Finance cost	4	2	4	—	—
		21,518	**22,869**	**31,720**	**22,466**	**13,590**

During years 2014 and 2016 the Group received financial advisory services for the Group's funding purposes from a company under the control of one of its executive directors. The services were rendered at cost plus a mark-up.

The following amounts were outstanding at each balance sheet date:

Payables to related parties

		31 October		31 December		
	Nature of balance	2017	2016 (unaudited)	2016	2015	2014
Joint ventures	Financing	—	—	—	1	208
Energean Israel Limited	Technical services	1,749	—	—	—	—
Other related party "Seven Marine"	Vessel leasing	2,381	818	214	—	—
Key management	Financial advisory services	—	—	310	—	—
		4,130	818	524	1	208

Related party balances are included within trade payables.

Receivables from related parties

		As at 31 October		As at 31 December		
	Nature of balance	2017	2016 (unaudited)	2016	2015	2014
Other related parties "Seven Marine"	Sale and leasing of vessel	—	2,290	1,747	—	—
		—	2,290	1,747	—	—

Related party balances are included within trade and other receivables.

The amounts outstanding are unsecured and will be settled in cash. No guarantees have been given or received. No provisions have been made for doubtful debts in respect of the amounts owed by related parties.

33.2 Key management compensation

Key management personnel are those persons who have the authority and responsibility for planning, directing and controlling the activities of the Group. The definition of key management personnel includes directors (both executive and non-executive) and other executives from the management team with significant authority and responsibility for planning, directing and controlling the entity's activities. Key management personnel compensation comprises the following:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Short-term employee benefits	1,512	927	1,720	1,560	2,045
	1,512	**927**	**1,720**	**1,560**	**2,045**

33.3 Loans from related parties (Note 17)

		As at 31 October		As at 31 December		
	Nature of balance	2017	2016 (unaudited)	2016	2015	2014
Third Point Hellenic Recovery Fund L.P. (Shareholder—interest 44.61%)—Note 17	Principal	—	179,653	179,653	179,653	125,000
Third Point Hellenic Recovery Fund L.P. (Shareholder—interest 44.61%)—Note 17	Accrued interest, net of discount	—	27,629	35,160	6,528	(8,432)
Growthy Holdings CO Limited (Shareholder—interest 24.60%)—Note 9	Principal	—	4,750	4,750	—	—
Growthy Holdings CO Limited (Shareholder—interest 24.60%)—Note 9	Accrued interest	—	10	35	—	—
Oilco Investments Limited (Shareholder—interest 24.60%) Note 9	Principal	—	4,750	4,750	—	—
Oilco Investments Limited (Shareholder—interest 24.60%) Note 9	Accrued interest	—	10	35	—	—
Adobelero Holdings CO Limited (Shareholder—interest 3.75%) Note 9	Principal	—	500	500	—	—
Adobelero Holdings CO Limited (Shareholder—interest 3.75%) Note 9	Accrued interest	—	2	4	—	—
		—	**217,304**	**224,887**	**186,181**	**116,568**

33.4 Reorganisation

On 30 June 2017 the Group entered into a Reorganisation Agreement which was subsequently amended by the "Supplementary Agreement" dated 31 October 2017. The Reorganisation Agreement is between the Company and the existing shareholders of Energean E&P Holdings (the Existing Shareholders), Energean E&P Holdings, Energean Israel and Energean International. Under the Reorganisation Agreement, the Company became the holding company of the Group (see Note 1.1) and the senior secured loan from Third Point and certain other parties was discharged in exchange for $224 million preference shares in Energean International Limited.

The preference shares in Energean International Limited have no voting rights. Rights to future capital and distributions comprise the right to a return of capital of $224 million upon winding up of Energean Israel Limited and, as clarified in the Supplementary Agreement dated 31 October, priority over distributions to the Company's ordinary shareholders up to an amount of $224 million.

Under the Reorganisation Agreement dated 30 June 2017 and the subsequent Supplementary Agreement dated 31 October 2017, the Group also made the following commitments:

- Under the Reorganisation Agreement dated 30 June 2017, in the event of an Exit transaction as defined in the Reorganisation Agreement, the Group committed to acquire the preference shares in Energean Israel Limited. Consideration would be in the form of ordinary shares of the Company to the value of $224 million in the event of a Sale transaction or $240 million in the case of an IPO. Under the Reorganisation Agreement, each of Third Point and the Founders may at any time propose an Exit Event at which time each of the other parties to this Agreement shall: (i) give such co-operation and assistance as such Parties may reasonably request; and (ii) use all reasonable endeavours to procure that such Exit Event is achieved in accordance with such proposal, and therefore the contingent

settlement provision of the preference shares represented a financial liability at 30 June 2017, initially recognised at its fair value and subsequently carried at amortised cost (see Note 36.2 for the impact on the consolidated historical financial information). Under the Supplementary Agreement dated 31 October 2017, the process to implementation of an Exit Event (whether by reference to an IPO or Sale) requires the consent of each of Third Point, the Founders and the Company, therefore the liability recognized was extinguished on 31 October 2017 with no impact on profit or loss.

- Under the Reorganisation Agreement dated 30 June 2017, in the event of an Exit transaction as defined in the Reorganisation Agreement, the Group committed to acquire the Founders' 50% interests in the B shares of Energean Israel Limited which represent 50% of the beneficial ownership of Israel. Taken together with the Group's A shares of Energean Israel Limited (see Note 9), this would result in Energean Israel becoming a 50% joint venture investee of the Group. Consideration would be in the form of ordinary shares of the Company to the value of $50 million in the event of a Sale transaction or $150 million in the case of an IPO.
- Under the Reorganisation Agreement, the Group was contractually obliged to pursue an Exit transaction, and therefore the contingent share purchase represented a derivative financial instrument at 30 June 2017, carried at fair value through profit and loss (see Note 36.2). Pursuant to the terms of the Supplementary Agreement the Company agreed to acquire the Energean Israel Limited Class B Shares from its founders shareholders upon the occurrence of:
  - (i) a Sale for US$10 million in cash (rather than for the issue of New Shares as contemplated by the Reorganisation Agreement); or
  - (ii) an IPO for US$10 million in cash (rather than for the issue of New Shares as contemplated by the Reorganisation Agreement).

The impact of the Supplementary Agreement on the derivative financial instrument was recognized as a credit to equity.

34. Legal cases and other contingent liabilities

34.1 Other contingent liabilities

The Group had no material contingent liabilities as of 31 October 2017, 31 October 2016 and as of 31 December 2016, 2015 and 2014.

35. Commitments

35.1 Operating lease commitments

The non-cancellable operating lease agreements entered by the Group relate mainly to:

- Lease of supply vessel Valiant Energy;
- Lease of supply vessel Energean Wave;
- Offices rental; and
- Vehicles lease.

The total operating lease expenses for the ten months ended 31 October 2017 amounted to US$299 (ten months ended 31 October 2016 US$224, years ended 31 December 2016: US$251, 2015: US$278, 2014: US$321).

The future aggregate minimum lease payments under non-cancellable operating leases are as follows:

	For the ten months ended 31 October		For the year ended 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Within one year	6,338	5,680	6,546	279	284
Between one and five years	686	825	5,904	567	740
After five years	86	290	219	457	660
	7,110	**6,795**	**12,669**	**1,303**	**1,684**

35.2 Performance guarantees

Energean Israel Limited, on 25 December 2016, submitted to the Petroleum Commissioner two irrevocable bank guarantees issued by HSBC of US$10 million each, for each of the Karish and Tanin Leases, to secure compliance with the leases and related liabilities. The guarantees replace the respective guarantees in the amount of US$7.5 million each given by the previous leaseholders, Noble, Delek, and Avner.

Energean Oil & Gas S.A. on behalf of Energean International Limited has issued a Letter of Guarantee of US$6,000 to beneficiary Ganoub El Wadi Holding Petroleum (GANOPE), which is the Egyptian Oil Commissioning Authority in respect of the capital and financial commitments of its related entity, Energean International Limited, in the area of West Kom Ombo. As of 31 October 2017, the US$6,000 guarantee has been reduced to US$2,225 and is now due to expire on 2 April 2018.

The Group provided a performance guarantee for the amount of US$619 (€587) issued to the Greek Ministry of Environment Energy and Climate Change in respect to the contract with the Greek State for exploitation in Prinos. See Note 15.2.

In relation to the investment in the areas of Ioannina and Katakolo, Energean Oil & Gas S.A. and its partners proceeded to provide bank guarantees in favour of the Greek Ministry of Environment & Energy for the total amounts of US$8,600 (€7,900), and US$751 (€690), for each area respectively. The purpose of these guarantees is the security of the minimum expenditure obligation per area, by Energean Oil & Gas S.A. and its partners as this derives from the provisions of the respective lease agreement.

As of 31 December 2016, the US$8,600 (€7,900) performance bank guarantee related to Ioannina block has been reduced to US$6,507 (€6,173) while as of 31 October 2017 has been further reduced to US$6,468 (€5,558), and will be further reduced from time to time to represent the remaining minimum expenditure obligations. For the security of any bank claim on the aforementioned guarantees, Energean Oil & Gas S.A. proceeded to restricting an amount of US$2,601 (€2,235), which corresponds to its 40% participating interest as described in Note 15.2.

The performance bank guarantee of US$379 (€360) related to Katakolo block has already expired since Energean Oil & Gas S.A. has executed the committed minimum expenditure.

A €3.0 million guarantee from Energean Montenegro limited in favour of the state of Montenegro, due to expire 14 October 2020, relating to the Group's concession and mandatory work programme in Montenegro. The guarantee is secured by a €3.0 million cash deposit (see Note 15.2).

35.3 Contingent Consideration

Energean Israel Limited has an obligation to pay a total additional amount of one hundred and eight million and five hundred thousand dollars (US$108,500) in ten equal annual payments for the acquisition of the Tanin and Karish offshore Israel leases as described in Note 9.1. This additional payment represents contingent consideration that is not recognised within the consolidated historical financial information. The contingent consideration is due on the earlier of the date on which a final investment decision of Energean Israel Limited has been made or the date on which the aggregate expenditures in connection with the Israeli leases exceed US$150,000.

36. Financial assets and liabilities

36.1. Carrying amount

The carrying amount of each class of financial assets and liabilities included in the consolidated statement of financial position is as follows:

	Notes	As at 31 October 2017	As at 31 October 2016 (unaudited)	As at 31 December 2016	As at 31 December 2015	As at 31 December 2014
Financial assets						
Measured at amortised cost:						
Cash and cash equivalents and bank deposits	15, 9	8,663	24,642	17,586	8,238	14,327
Trade and other receivables	12	335	10,806	2,146	973	1,330
Measured at Fair Value through Profit or Loss:						
Derivative asset		91,615	—	—	—	—
		100,613	**35,448**	**19,732**	**9,211**	**15,657**
Financial liabilities at amortised cost						
Borrowings	17, 9	79,186	268,453	310,415	187,402	117,930
Trade and other payables	21	52,773	32,090	26,547	26,271	17,271
		131,959	**300,543**	**336,962**	**213,673**	**135,201**

36.2. Fair value measurements

The information set out below provides information about how the Group determines fair values of various financial assets and liabilities.

The fair values of the Group's financial assets and liabilities measured at amortised cost approximate to their carrying amounts at the reporting date. The carrying value less any estimated credit adjustments for financial assets and financial liabilities with a maturity of less than one year are assumed to approximate their fair values due to their short term-nature.

The Group has only one material financial asset measured at fair value at 31 October 2017 which relates to the Energean Israel B shares. As part of the reorganisation, the Group committed to acquire the 50% of the class B shares of Energean Israel Limited in an Exit Event (See Note 33.4).

The valuation technique used multiplies the estimated likelihood of an Exit (being an IPO or a Sale) by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares to be acquired under the commitment. The key input assumptions used in the fair value measurement calculation are the estimated likelihood of an IPO event and value of the B shares. An Exit in the form of a Sale is considered to be of negligible likelihood. The other significant inputs are the transaction prices applicable in an Exit Event, which are contractually agreed amounts, and the discount rate assumption used in the calculation which was 11.5%. The fair value of the derivative asset is a Level 3 fair value measurement in the fair value measurement hierarchy, because the valuation relies significantly on input assumptions that are unobservable.

On remeasurement on 31 October 2017, the value of the B shares was estimated based on the price negotiated at a similar time with a third party for another tranche of the B shares in a separate transaction. The likelihood of a future IPO occurring was estimated as of 31 October 2017 to be 50% having regard to the considerable progress made to prepare for an IPO as of that date, but also to the fact that there were a number of significant steps not wholly under the control of the Group that remained to be achieved, and the inherent uncertainty in achieving any IPO due to capital market conditions.

The change in fair value of US$24,109 between 30 June 2017 and 31 October 2017 is included in "Gain on derivative" in the consolidated statement of profit or loss as it is due to changes in measurement assumptions.

Also on 31 October 2017, under the Supplementary Agreement (see Note 33.4) the consideration payable to acquire the B shares in the event of an IPO was reduced from $150m to $10m. The resulting increase in the value of the derivative asset of US$67,506 (after applying the 50% IPO likelihood assumption and other discounting effects) is recorded in the consolidated statement of changes in equity as the Supplementary Agreement is a transaction with owners, giving the derivative asset a closing value of $91,615.

If the probability of an IPO increased to 100%, whilst the probability of a sale was 0% and the discount rate held constant the fair value of the derivative asset to purchase Energean Israel Class B Shares at 31 October 2017 would increase by US$91,615.

If the discount rate increased from 11.5% to 20%, whilst the probability of an IPO and probability of a sale held constant the fair value of the derivative asset to purchase Energean Israel Class B Shares at 31 October 2017 would decrease by US$2,216.

Upon recognition, the derivative was the only instrument in the Level 3 category of the fair value hierarchy. There were no transfers in or out of this category in the period, and the only movement in the category relates to the increase in fair value of the derivative.

The fair value hierarchy of financial assets and financial liabilities that are not measured at fair value (but fair value disclosure is required) is as follows:

	Fair value hierarchy as at 31 October 2017			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets				
Trade and other receivables	—	335	—	335
Cash and cash equivalents and bank deposits	8,663	—	—	8,663
Total	**8,663**	**335**	**—**	**8,998**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	—	79,186	—	79,186
Trade and other payables	—	52,773	—	52,773
Total	**—**	**131,959**	**—**	**131,959**

	Fair value hierarchy as at 31 October 2016			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets				
Trade and other receivables	—	10,806	—	10,806
Cash and cash equivalents and bank deposits	24,642	—	—	24,642
Total	**24,642**	**10,806**	**—**	**35,448**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	—	278,475	—	278,475
Trade and other payables	—	32,090	—	32,090
Total	**—**	**310,565**	**—**	**310,565**

	Fair value hierarchy as at 31 December 2016			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets				
Trade and other receivables	—	2,146	—	2,146
Cash and cash equivalents and bank deposits	17,586	—	—	17,586
Total	**17,586**	**2,146**	**—**	**19,732**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	—	276,248	—	276,248
Convertible loan notes	—	34,167	—	34,167
Trade and other payables	—	26,547	—	26,547
Total	**—**	**336,962**	**—**	**336,962**

	Fair value hierarchy as at 31 December 2015			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets				
Trade and other receivables	—	973	—	973
Cash and cash equivalents and bank deposits	8,238	—	—	8,238
Total	**8,238**	**973**	**—**	**9,211**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	—	187,402	—	187,402
Trade and other payables	—	26,272	—	26,272
Total	**—**	**213,674**	**—**	**213,674**

	Fair value hierarchy as at 31 December 2014			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets				
Trade and other receivables	—	1,330	—	1,330
Cash and cash equivalents and bank deposits	14,327	—	—	14,327
Total	**14,327**	**1,330**	**—**	**15,657**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	—	117,930	—	117,930
Trade and other payables	—	17,271	—	17,271
Total	**—**	**135,201**	**—**	**135,201**

There were no transfers between Level 1, Level 2 and Level 3 fair value measurements during the year.

37. Financial risk management

The Group's Treasury function provides services to the business and monitors and manages the financial risks relating to the operations of the Group through internal reporting which analyse exposures by degree and magnitude of risk. These risks include market risk (interest rate risk, credit risk, foreign exchange risk, liquidity risk.

The Treasury function reports monthly to the Board of Directors to monitor risks and policies implemented to manage risk exposures.

37.1 Interest rate risk

The Group's policy is to minimise interest rate cash flow risk exposures on long-term financing. Longer-term borrowings are therefore usually at fixed rates. At 31 October 2017, the Group is exposed to changes in market interest rates through bank borrowings at variable interest rates. Other borrowings are at fixed interest rates. The exposure to interest rates for the Group's money market funds is considered immaterial.

The following table illustrates the sensitivity of profit to a reasonably possible change in interest rates of +/- 1%. These changes are considered to be reasonably possible based on observation of current market conditions. The calculations are based on a change in the average market interest rate for each period, and the financial instruments held at each reporting date that are sensitive to changes in interest rates. All other variables are held constant.

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Variable rate instruments					
Financial liabilities	77,880	59,943	60,253	—	—
	77,880	**59,943**	**60,253**	**—**	**—**

Interest rate sensitivity

	Profit and equity for the period	
	+1%	-1%
31 October 2017	528	(528)
31 October 2016	188	(188)
31 December 2016	305	(305)

37.2 Credit risk

Credit risk arises when a failure by counterparties to discharge their obligations could reduce the amount of future cash inflows from financial assets on hand at the reporting date. The Group has policies in place to ensure that all of its transactions giving rise to credit risk are made with parties having an appropriate credit history and monitors on a continuous basis the ageing profile of its receivables.

Also, the Group has policies to limit the amount of credit exposure to any banking institution, considering among other factors the credit ratings of the banks with which deposits are held. Credit quality information in relation to those banks is provided below.

The carrying amount of financial assets represents the maximum credit exposure. The maximum exposure to credit risk at the reporting date, without taking account of any collateral obtained, was:

	As at 31 October		As at 31 December		
	2017	2016 (unaudited)	2016	2015	2014
Trade receivables	280	10,702	2,143	386	437
Other receivables	67	104	3	587	893
Cash and cash equivalents and bank deposits	8,663	24,642	17,586	8,238	14,327
Total	**9,010**	**35,448**	**19,732**	**9,211**	**15,657**

Credit quality of non-impaired bank deposits

The credit quality of the banks in which the Group keeps its non-impaired deposits is assessed by reference to the credit rating of these banks. The credit ratings of the corresponding banks in which of the Group keeps its deposits as follows:

AA / Aa2
AA- / Aa3
Lower than B- / B3

The Company has assessed the recoverability of all cash balances and believe they are presented at fair value within the consolidated statement of financial position.

37.3 Foreign exchange risk

The Group is exposed to foreign exchange risk as it undertakes operations in various foreign currencies. The key sources of the risk are attributed to the fact that the Group has certain subsidiaries with Euro functional currencies in which a number of loan agreements denominated in US$ and sales of crude oil are additionally denominated in US$.

The Group's exposure to foreign currency risk at each reporting date is shown in the table below. The amounts shown are the US$ equivalent of the foreign currency amounts.

	Liabilities		Assets	
	As at 31 October		As at 31 October	
	2017	2016	2017	2016
US$ (Amounts in US$'000)	77,880	269,487	745	8,926
United Kingdom Pounds (Amounts in GBP'000)	962	593	8	—
Total	**78,842**	**270,080**	**753**	**8,926**

	Liabilities			Assets		
	As at 31 December			As at 31 December		
	2016	2015	2014	2016	2015	2014
US$ (Amounts in US$'000)	272,441	189,751	117,464	6,423	1,485	8,056
United Kingdom Pounds (Amounts in US$'000)	1,741	125	1,151	3	19	1
Total	**274,182**	**189,876**	**118,615**	**6,426**	**1,504**	**8,057**

The following table reflects the sensitivity analysis for profit and loss results for the year and equity, taking into consideration for the periods presented foreign exchange variation by +/- 10%.

	31 October 2017				31 October 2016			
	USD		GBP		USD		GBP	
	Variation		Variation		Variation		Variation	
	10%	-10%	10%	-10%	10%	-10%	10%	-10%
Profit or loss (before tax)	6,751	(8,251)	77	(111)	24,125	(29,487)	55	(67)
Other comprehensive income	(768)	1,400	—	—	2,006	(2,124)	—	—
Equity	**5,983**	**(6,851)**	**77**	**(111)**	**26,131**	**(31,611)**	**55**	**(67)**

	31 December 2016				31 December 2015				31 December 2014			
	USD		GBP		USD		GBP		USD		GBP	
	Variation		Variation		Variation		Variation		Variation		Variation	
	10%	-10%	10%	-10%	10%	-10%	10%	-10%	10%	-10%	10%	-10%
Profit or loss (before tax)	25,395	(31,038)	166	203	17,442	(21,318)	10	(12)	10,883	(13,302)	114	(140)
Other comprehensive income	1,551	(2,707	—	—	5,637	(5,130)	—	—	8,754	(6,152)	—	—
Equity	**26,946**	**(33,745)**	**166**	**203**	**23,079**	**(26,448)**	**10**	**(12)**	**19,637**	**(19,454)**	**114**	**(140)**

The above calculations assume that interest rates remain the same as at the reporting date.

37.4 Liquidity risk

Liquidity risk is the risk that arises when the maturity of assets and liabilities does not match. An unmatched position potentially can increase the risk of losses. The Group has procedures with the object of minimising such losses such as maintaining sufficient cash and other highly liquid current assets and by having available an adequate amount of committed credit facilities.

The following tables detail the Group's remaining contractual maturity for its financial liabilities. The tables have been drawn up based on the undiscounted cash flows of financial liabilities based on the earliest date on which the Group can be required to pay. The table includes both interest and principal cash flows.

The Group manages its liquidity risk by ongoing monitoring of its cash flows. The Management budgets and follows up its cash flows and appropriately acts for available cash deposits and credit lines with the banks.

As part of the derivative asset recognition under the Reorganisation and Supplementary Agreement (Note 33.4), there is a contractual cash flow of US$10 million to be paid on either a Sale transaction or an IPO. The carrying value of the derivative asset as of 31 October 2017 is US$91,615.

31 October 2017	Carrying amounts	Contractual cash flows	3 months or less	3-12 months	1-2 years	2-5 years	More than 5 years
Bank loans	77,880	101,312	—	4,971	29,229	54,543	12,569
Other loans	1,306	1,306	—	—	1,309	—	—
Trade and other payables	57,163	57,163	39,534	15,577	503	1,508	41
	136,349	**159,781**	**39,534**	**20,548**	**31,041**	**56,051**	**12,610**

31 October 2016 (unaudited)	Carrying amounts	Contractual cash flows	3 months or less	3-12 months	1-2 years	2-5 years	More than 5 years
Bank loans	59,943	74,657	1,195	3,148	4,328	65,986	—
Other loans	1,228	1,228	—	—	—	1,228	—
Trade and other payables	36,917	36,917	22,152	11,811	473	1,418	1,063
Loans from shareholders	217,304	324,573	—	34,082	50,913	239,578	—
	315,392	**437,375**	**23,347**	**49,041**	**55,714**	**308,210**	**1,063**

31 December 2016	Carrying amounts	Contractual cash flows	3 months or less	3-12 months	1-2 years	2-5 years	More than 5 years
Investor loans (Note 9.1)	34,167	35,000	—	35,000	—	—	—
Bank loans	60,253	73,169	858	3,024	3,860	65,427	—
Other loans	1,182	1,182	—	—	1,182	—	—
Trade and other payables	26,547	26,547	26,547	—	—	—	—
Loans from shareholders	214,813	324,573	—	21,130	42,263	261,180	—
	336,962	**460,471**	**27,405**	**59,154**	**47,305**	**326,607**	**—**

31 December 2015	Carrying amounts	Contractual cash flows	3 months or less	3-12 months	1-2 years	2-5 years	More than 5 years
Other loans	1,221	1,221	—	—	—	1,221	—
Trade and other payables	24,953	24,953	24,953	—	—	—	—
Loans from shareholders	186,181	312,398	—	—	—	312,398	—
	212,355	**338,572**	**24,953**	**—**	—	**313,619**	**—**

31 December 2014	Carrying amounts	Contractual Cash flows	3 months or less	3-12 months	1-2 years	2-5 years	More than 5 years
Other loans	1,362	1,362	—	—	—	1,362	—
Trade and other payables	15,717	15,717	15,717	—	—	—	—
Loans from related companies	116,568	156,284	4,178	—	14,623	137,483	—
	133,647	**173,363**	**19,895**	**—**	**14,623**	**138,845**	**—**

38. Other risk management

38.1 Inventory market price risk

External market conditions can impact our financial performance. Supply, demand and the prices achieved for our products can be affected by a wide range of factors including political developments, technological change, global economic conditions and the influence of OPEC.

Hedging activity

The Group does not have a formal hedging policy with regard to the oil price and is limited in the scope of its hedging activities under the terms of its facility agreements with the EBRD. Historically, hedging has been undertaken via zero cost collars for general downside risk and fixed price contracts to set a fixed price for a set number of barrels for a known future BP lifting to protect against either (i) a fall in the oil price and/or (ii) the pricing optionality afforded to BP under the BP Offtake Agreement.

38.2 Customer concentration risk

The Group's revenue is derived from a single major customer. The loss of this customer would adversely affect the Group's financial position and operating results. The Group takes all reasonable steps to retain good relationship with that customer.

39. Capital management

The Group for management purposes determines as capital, defined as total equity, including all reserves, plus its shareholders subordinated debt.

Shareholders subordinated debt represents loans from the shareholders of the Group. The Group defines net debt as the Group's total borrowings (including current and non-current borrowings) less cash and cash equivalents.

The Group manages its capital and net debt to ensure that it will be able to continue as a going concern while maximising the return to shareholders through the optimisation of the balance between its net debt and capital.

The Group manages the capital structure and takes reasonable steps in the light of changes in the economic conditions and the risk characteristics of its underlying business and assets. In order to maintain or improve its capital structure the Group may issue new shares, sell assets to reduce debt, refinance existing borrowings, and adjust the amount of any distribution of dividends.

The net debt at the end of the period are calculated using the following amounts, as shown in the consolidated statement of financial position:

	31 October		31 December		
	2017	2016 (unaudited)	2016	2015	2014
Bank and other loans	79,187	61,171	61,435	1,221	1,362
Cash and cash equivalents and bank deposits	(8,663)	(24,642)	(12,977)	(8,238)	(14,327)
Net debt from third parties	**70,524**	**36,529**	**48,458**	**(7,017)**	**(12,965)**
Total equity	282,895	1,154	(16,114)	20,099	59,326
Shareholders subordinated debt	—	217,304	214,813	186,181	116,568
Capital	**282,895**	**218,458**	**198,699**	**206,280**	**175,894**
Gearing ratio (Net debt/Capital)	24.93%	16.72%	24.39%	-3.40%	-7.37%

40. Subsequent events

On 28 December 2017, the Group, the Founders and Kerogen entered into a subscription agreement, pursuant to which the Group agreed to subscribe for additional shares in Energean Israel Limited for an aggregate consideration of US$266.7 million, payable in cash. Upon completion of such subscription, the Group would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%.

On 8 December 2017, the Group signed an US$88.3 million EPCIC (engineering, procurement, construction, installation and commissioning) contract with GSP Offshore S.R.L. for drilling and construction related to the Epsilon development program, including the Lamda production facilities and three development wells.

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities—a facility of up to US$105 million with EBRD and the Black Sea Trade and Development Bank ("BSTDB") as lenders (the "IFI Facility") and a US$75 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA ("Romanian ECA") and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders (the "Romanian Club Facility"). Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP EPCIC Contract.

On 12 February 2018, the Group signed an amendment to the BP Offtake Agreement to extend the contract to supply the produced Prinos crude Oil to BP Oil International until the later of a) the expiry of the agreement on 1 November 2025 or b) the delivery of twenty-five million barrels.

PART 14
UNAUDITED PRO FORMA FINANCIAL INFORMATION

Section A—Unaudited consolidated pro forma statement of net assets as at 31 October 2017

The unaudited consolidated pro forma statement of net assets (the "**Pro forma financial information**") set out below has been prepared to illustrate the effects of the Reorganisation and the Global Offer on the net assets of the Group had the Reorganisation and the Global Offer taken place on 31 October 2017.

The Pro forma financial information is based on the consolidated statement of financial position of the Group as at 31 October 2017 contained in Section B of Part 13 of this Prospectus.

The Pro forma financial information has been prepared in a manner consistent with the accounting policies applied in preparing the Consolidated Historical Financial Information set out in Section B of Part 13, the basis set out in the notes below and in accordance with the requirements of items 1 to 6 of Annex II of the Prospectus Directive Regulation.

The Pro forma financial information has been prepared for illustrative purposes only, and by its nature addresses a hypothetical situation and, therefore, does not reflect the Group's actual financial position or results. It may not therefore give a true picture of the Group's financial position or results, nor is it indicative of the results that may or may not be achieved in the future.

		Pro forma adjustments		
	Consolidated net assets of the Group at 31 October 2017	Net proceeds of the Global Offer	Reorganisation	Consolidated pro forma statement of net assets of the Group as at 31 October 2017
	US$'000			
	(Note 1)	(Note 2)	(Note 3)	
Assets				
Non-current assets				
Property plant and equipment	290,318	—	—	290,318
Intangible assets	3,616	—	—	3,616
Investments in Joint Ventures	—	—	101,615	101,615
Other non-current assets	575	—	—	575
Deferred tax asset	16,761	—	—	16,761
Bank deposits	1,828	—	—	1,828
Total non-current assets	**313,098**	**—**	**101,615**	**414,713**
Current assets				
Inventories	14,276	—	—	14,276
Trade and other receivables	11,716	—	—	11,716
Derivative asset	91,615	—	(91,615)	—
Cash and cash equivalents	6,835	447,500	(10,000)	444,335
Total current assets	**124,442**	**447,500**	**(101,615)**	**470,327**
Total assets	**437,540**	**447,500**	**—**	**885,040**
Liabilities				
Non-current liabilities				
Borrowings	79,186	—	—	79,186
Deferred tax liabilities	3,732	—	—	3,732
Provisions for liabilities	6,749	—	—	6,749
Trade and other payables	2,555	—	—	2,555
Total non-current liabilities	**92,222**	**—**	**—**	**92,222**
Current liabilities				
Trade and other payables	54,607	—	—	54,607
Current tax liabilities	2,605	—	—	2,605
Provisions for liabilities	5,218	—	—	5,218
Total current liabilities	**62,430**	**—**	**—**	**62,430**
Total liabilities	**154,652**	**—**	**—**	**154,652**
Net assets	**282,888**	**447,500**	**—**	**730,388**

Notes:

(1) The net assets of the Company have been extracted without adjustment, from the Consolidated Historical Financial Information as set out in Section B of Part 13 of this Prospectus. As at 31 October 2017, the net assets of the Company amounted to US$282.9 million, represented by issued ordinary share capital of US$0.9 million as set out in Section B of Part 13 "*Consolidated Historical Financial Information*".

(2) As set out in Section 1 of Part 15 of this Prospectus the total net proceeds received by the Company from the Global Offer are estimated to be approximately US$447.5 million, after deduction of transaction related costs of US$12.5 million.

(3) On Admission and pursuant to the terms of the Reorganisation, the Company agreed to acquire 50% of the EISL Class B Shares of Energean Israel Limited from its Founders for US$10 million in cash. On completion of the acquisition of the EISL class B shares of Energean Israel Limited (a contingent purchase obligation arising through the Reorganisation) the Group will derecognise the fair value of the obligation (US$91.6 million derivative asset at 31 October 2017). The combined amount of the cash payment and derecognition of the obligation is presented as an investment in Joint Venture. For the Pro Forma this combined amount is US$101.6 million based on the amounts at 31 October 2017, whereas the actual amount will reflect the fair value of the derivative asset as at the actual date of derecognition of the derivative asset.

Additional Information

This Pro forma financial information does not constitute financial statements within the meaning of section 434 of the Companies Act 2006.

On 28 December 2017, Energean E&P Holdings, Energean Israel, the Founders and Kerogen entered into the Second EISL Subscription Agreement, pursuant to which the Energean E&P Holdings agreed to subscribe for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash. Upon completion of such subscription, the Group would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018. The effect of such subscription has not been reflected in the Pro forma financial information as it would take place subsequent to Admission and it remains conditional at Admission.

On Admission and pursuant to the terms of the Reorganisation, the Energean International Preference Shares held by Third Point will be converted to common shares in the Company. This conversion solely impacts equity and non-controlling interests and has no impact on net assets. As a result, this transaction has not been reflected in the Pro forma financial information. The reorganisation on Admission is discussed in paragraph 3.1 of Part 9 "*Reorganisation in connection with Admission*" of this Prospectus.

The Pro forma financial information does not reflect any changes in the trading position of the Group or any other changes arising from other transactions, other than those outlined in the above notes, since 31 October 2017.

Deloitte.

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16 March 2018

Dear Sirs/Madams

Energean Oil & Gas plc (the "Company")

We report on the pro forma financial information (the "**Pro forma financial information**") set out in Section A of Part 14 of the prospectus dated 16 March 2018 (the "**Prospectus**"), which has been prepared on the basis described in notes 1 to 3, for illustrative purposes only, to provide information about how the transaction might have affected the Consolidated Historical Financial Information presented on the basis of the accounting policies adopted by the Company in preparing the Consolidated Historical Financial Information for the period ended 31 October 2017. This report is required by the Commission Regulation (EC) No 809/2004 (the "**Prospectus Directive Regulation**") and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the directors of the Company (the "**Directors**") to prepare the Pro forma financial information in accordance with Annex II items 1 to 6 of the Prospectus Directive Regulation.

It is our responsibility to form an opinion, as to the proper compilation of the Pro forma financial information and to report that opinion to you in accordance with Annex II item 7 of the Prospectus Directive Regulation.

Save for any responsibility arising under Prospectus Rule 5.5.3R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Annex I item 23.1 of the Prospectus Directive Regulation, consenting to its inclusion in the Prospectus.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro forma financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards or practices.

Opinion

In our opinion:

(a) the Pro forma financial information has been properly compiled on the basis stated; and

(b) such basis is consistent with the accounting policies of the Company.

Declaration

For the purposes of Prospectus Rule 5.5.3R(2)(f) we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex I item 1.2 of the Prospectus Directive Regulation.

Yours faithfully

Deloitte LLP

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PART 15
DETAILS OF THE GLOBAL OFFER

1. Background

Pursuant to the Global Offer, the Company intends to issue 72,592,016 New Shares, raising proceeds of approximately £330 million (approximately US$460 million), before underwriting commissions and other estimated fees and expenses of approximately £9 million. The New Shares will represent approximately 48% of the expected issued ordinary share capital of the Company immediately following Admission.

In the Global Offer, Shares will be offered (i) to certain institutional investors in the United Kingdom and elsewhere outside the United States and (ii) in the United States only to qualified institutional buyers in reliance on Rule 144A or pursuant to another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act.

Certain restrictions that apply to the distribution of this Prospectus and the Shares being issued under the Global Offer in jurisdictions outside the United Kingdom are described below.

When admitted to trading, the Shares will be registered with ISIN number GB00BG12Y042 and SEDOL (Stock Exchange Daily Official List) number BG12Y04 and trade under the symbol "ENOG".

Immediately following Admission, it is expected that in excess of 25% of the Company's issued ordinary share capital will be held in public hands (within the meaning of paragraph 6.14.1 of the Listing Rules).

No expenses will be charged by the Company to any investor who purchases Shares pursuant to the Global Offer.

Pursuant to the Global Offer, existing Shareholders will experience a 48% dilution from the issue of 72,592,016 New Shares (i.e., its, his or her proportionate interest in the Company will drop by 48%).

Following completion of the Global Offer, the Board will consider a secondary listing of the Shares on the Tel Aviv Stock Exchange. No assurance can be given that an application will ultimately be made to the Tel Aviv Stock Exchange or, if such an application is ultimately made, that it would be successful.

2. Reasons for the Global Offer

The Directors believe that the Global Offer will:

- provide funding required for investment in the Group's development projects and organic growth of the existing producing asset base; and
- further increase the Group's profile and brand recognition.

3. Use of Proceeds

The Company expects to raise gross proceeds of approximately £330 million (approximately US$460 million) in the Global Offer, of which:

- approximately US$405 million will be used to fund investment in the development of the Karish and Tanin gas fields offshore Israel, including the US$80 million carry payable by Energean E&P Holdings to increase its interest in Energean Israel to 70% (as part of the consideration payable under the Second EISL Subscription Agreement);
- US$10 million will be used to repay, at face value, a bridge investment from the Founders used to contribute to the acquisition costs of the Karish and Tanin assets;
- approximately US$13 million will be used for IPO transaction fees and expenses; and
- approximately US$32 million will be used for exploration capital expenditure and other corporate purposes.

4. Allocation

The rights attaching to the Shares will be uniform in all respects and they will form a single class for all purposes. The Shares allocated under the Global Offer have been underwritten, subject to certain conditions, by the Underwriters as described in the paragraph headed "*Underwriting arrangements*" below and in paragraph 10 of Part 16 "*Additional Information—Underwriting Arrangements*". Allocations under the Global Offer will be determined at the sole discretion of the Company and the Major Shareholders after having received a

recommendation from the Joint Global Co-ordinators. All Shares issued pursuant to the Global Offer will be issued, payable in full, at the Offer Price. Liability for UK stamp duty and stamp duty reserve tax is described in paragraph 13 of Part 16 "*Additional Information – UK Taxation*".

5. Dealing arrangements

The Global Offer is subject to the satisfaction of certain conditions contained in the Underwriting Agreement, which are typical for an agreement of this nature. Certain conditions are related to events which are outside the control of the Company, the Directors and the Underwriters. Further details of the Underwriting Agreement are described in paragraph 10.1 of Part 16 "*Additional Information—Underwriting Arrangements—Underwriting Agreement*".

Application has been made to the FCA for the Shares to be admitted to the premium listing segment of the Official List of the FCA and to the London Stock Exchange for such Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

Conditional dealings in the Shares are expected to commence on the London Stock Exchange on 16 March 2018. Dealings on the London Stock Exchange before Admission will only be settled if Admission takes place. The earliest date for such settlement of dealings will be 21 March 2018. It is expected that Admission will become effective, and that unconditional dealings in the Shares will commence on the London Stock Exchange at 8.00 a.m. (London time) on 21 March 2018. Settlement of dealings from that date will be on a two-day rolling basis. **All dealings before the commencement of unconditional dealings will be of no effect if Admission does not take place and such dealings will be at the sole risk of the parties concerned. These dates and times may be changed without further notice.**

Each investor in the underwritten portion of the Global Offer will be required to undertake to pay the Offer Price for the Shares issued to such investor in such manner as shall be directed by the Joint Global Co-ordinators.

It is expected that Shares allocated to investors in the Global Offer will be delivered in uncertificated form and settlement will take place through CREST on Admission. No temporary documents of title will be issued. Dealings in advance of crediting of the relevant CREST stock account shall be at the risk of the person concerned.

6. CREST

CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another's without the need to use share certificates or written instruments of transfer.

Application has been made for the Shares to be admitted to CREST with effect from Admission. Accordingly, settlement of transactions in the Shares following Admission may take place within the CREST system if any shareholder so wishes. CREST is a voluntary system and holders of Shares who wish to receive and retain share certificates will be able to do so.

7. Underwriting arrangements

The Underwriters have entered into commitments under the Underwriting Agreement pursuant to which they have agreed, subject to certain conditions, to procure subscribers for the New Shares to be issued by the Company in the Global Offer, or, failing which, for the Underwriters to subscribe for such Shares, at the Offer Price. The Underwriting Agreement contains provisions entitling the Joint Global Co-ordinators to terminate the Underwriting Agreement (and the arrangements associated with it) at any time prior to Admission in certain circumstances. If this right is exercised, the Underwriting Agreement and these arrangements will lapse and any moneys received in respect of the Global Offer will be returned to applicants without interest. Any commissions received by the Underwriters may be retained, and any Shares acquired by them may be retained or dealt in, by them, for their own benefit.

Further details of the terms of the Underwriting Agreement are set out in paragraph 10.1 of Part 16 "*Additional Information—Underwriting arrangements—Underwriting Agreement*". Certain selling and transfer restrictions are set out below.

8. Lock-up arrangements

Pursuant to the Underwriting Agreement, the Company has agreed that, subject to certain exceptions, during the period of 180 days from the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, issue, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein or in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

Pursuant to the Underwriting Agreement and related arrangements, Third Point has agreed that, subject to certain exceptions, during the period of 180 days from the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

Pursuant to the Underwriting Agreement and related arrangements, the Founders, the Directors and certain members of the Company's management team have agreed that, subject to certain exceptions, during the period of 360 days from the date of Admission, they will not, without the prior written consent of the Joint Global Co-ordinators (not to be unreasonably withheld or delayed), directly or indirectly, offer, sell or contract to sell, or otherwise dispose of, directly or indirectly, or announce an offer of any Shares (or any interest therein in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

Further details of these arrangements, which are contained in the Underwriting Agreement, are set out in paragraph 10 of Part 16 "*Additional Information—Underwriting arrangements*".

9. Selling restrictions

The distribution of this Prospectus and the offer of Shares in certain jurisdictions may be restricted by law and therefore persons into whose possession this Prospectus comes should inform themselves about and observe any restrictions, including those set out in the paragraphs that follow. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

No action has been or will be taken in any jurisdiction that would permit a public offering of the Shares, or possession or distribution of this Prospectus or any other offering material in any country or jurisdiction where action for that purpose is required. Accordingly, the Shares may not be offered or sold, directly or indirectly, and neither this Prospectus nor any other offering material or advertisement in connection with the Shares may be distributed or published in or from any country or jurisdiction except in circumstances that will result in compliance with any and all applicable rules and regulations of any such country or jurisdiction. Persons into whose possession this Prospectus comes should inform themselves about and observe any restrictions on the distribution of this Prospectus and the offer of Shares contained in this Prospectus. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. This Prospectus does not constitute an offer to subscribe for or purchase any of the Shares to any person in any jurisdiction to whom it is unlawful to make such offer of solicitation in such jurisdiction.

9.1 European Economic Area

In relation to each member state of the European Economic Area which has implemented the Prospectus Directive (2003/71/EC) (each, a "**Relevant Member State**") no Shares have been offered or will be offered pursuant to the Global Offer to the public in that Relevant Member State prior to the publication of a prospectus in relation to the Shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that offers of Shares may be made to the public in that Relevant Member State at any time under the following exemptions under the Prospectus Directive, if they are implemented in that Relevant Member State:

(a) to any legal entity which is a qualified investor as defined under the Prospectus Directive;

(b) to fewer than 100, or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150 natural or legal persons in a Relevant Member State (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the Joint Global Co-ordinators; or

(c) in any other circumstances which do not require the publication by the Company of a prospectus pursuant to Article 3(2) of the Prospectus Directive,

provided that no such offer of Shares shall result in a requirement for the publication of a prospectus pursuant to Article 3 of the Prospectus Directive or any measure implementing the Prospectus Directive in a Relevant Member State or of a supplement to a prospectus pursuant to Article 16 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer to the public" in relation to any Shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and any Shares to be offered so as to enable an investor to decide to purchase any Shares, as the same may be varied in that member state by any measure implementing the Prospectus Directive in that member state. The expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in each Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

9.2 United States

The Shares have not been and will not be registered under the U.S. Securities Act or under any applicable securities laws or regulations of any state of the United States and, subject to certain exceptions, may not be offered or sold within the United States except to persons reasonably believed to be QIBs in reliance on Rule 144A or another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. The Shares are being offered and sold outside the United States in offshore transactions in reliance on Regulation S.

In addition, until 40 days after the commencement of the Global Offer of the Shares an offer or sale of Shares within the United States by any dealer (whether or not participating in the Global Offer) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A or another exemption from, or transaction not subject to, the registration requirements of the U.S. Securities Act.

The Underwriting Agreement provides that the Underwriters may directly or through their respective United States broker-dealer affiliates arrange for the offer and resale of Shares within the United States only to QIBs in reliance on Rule 144A or another exemption from, or transaction not subject to, the registration requirements of the U.S. Securities Act.

Each acquirer of Shares that are part of the underwritten portion of the Global Offer within the United States, by accepting delivery of this Prospectus, will be deemed to have represented, agreed and acknowledged that it has received a copy of this Prospectus and such other information as it deems necessary to make an investment decision and that:

(a) it is (a) a QIB within the meaning of Rule 144A, (b) acquiring the Shares for its own account or for the account of one or more QIBs with respect to whom it has the authority to make, and does make, the representations and warranties set forth herein, (c) acquiring the Shares for investment purposes, and not with a view to further distribution of such Shares, and (d) aware, and each beneficial owner of the Shares has been advised, that the sale of the Shares to it is being made in reliance on Rule 144A or in reliance on another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act.

(b) it understands that the Shares are being offered and sold in the United States only in a transaction not involving any public offering within the meaning of the U.S. Securities Act and that the Shares have not been and will not be registered under the U.S. Securities Act or with any securities regulatory authority of any state or other jurisdiction of the United States and may not be offered, sold, pledged or otherwise transferred except (a) to a person that it and any person acting on its behalf reasonably believe is a QIB purchasing for its own account or for the account of a QIB in a transaction meeting the requirements of Rule 144A, or another exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act, (b) in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S, (c) pursuant to an exemption from registration under the U.S. Securities Act provided by Rule 144 thereunder (if available) or (d) pursuant to an effective registration statement under the U.S. Securities Act, in each case in accordance with any applicable securities laws of any state of the United States. It further (a) understands that the Shares may not be deposited into any unrestricted depositary receipt facility in

respect of the Shares established or maintained by a depositary bank, (b) acknowledges that the Shares (whether in physical certificated form or in uncertificated form held in CREST) are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act and that no representation is made as to the availability of the exemption provided by Rule 144 for resales of the Shares and (c) understands that the Company may not recognise any offer, sale, resale, pledge or other transfer of the Shares made other than in compliance with the above-stated restrictions.

(c) it understands that the Shares (to the extent they are in certificated form), unless otherwise determined by the Company in accordance with applicable law, will bear a legend substantially to the following effect:

THE SHARES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR WITH ANY SECURITIES REGULATORY AUTHORITY OF ANY STATE OR OTHER JURISDICTION OF THE UNITED STATES AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) TO A PERSON THAT THE SELLER AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE U.S. SECURITIES ACT PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER, (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE U.S. SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE) OR (4) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE U.S. SECURITIES ACT, IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. NO REPRESENTATION CAN BE MADE AS TO THE AVAILABILITY OF THE EXEMPTION PROVIDED BY RULE 144 UNDER THE U.S. SECURITIES ACT FOR RESALES OF THE SHARES. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THE FOREGOING, THE SHARES REPRESENTED HEREBY MAY NOT BE DEPOSITED INTO ANY UNRESTRICTED DEPOSITARY RECEIPT FACILITY IN RESPECT OF THE SHARES ESTABLISHED OR MAINTAINED BY A DEPOSITARY BANK. EACH HOLDER, BY ITS ACCEPTANCE OF SHARES, REPRESENTS THAT IT UNDERSTANDS AND AGREES TO THE FOREGOING RESTRICTIONS; and

(d) it represents that if, in the future, it offers, resells, pledges or otherwise transfers such Shares while they remain "restricted securities" within the meaning of Rule 144, it shall notify such subsequent transferee of the restrictions set out above.

The Company, the Managers and their affiliates and others will rely on the truth and accuracy of the foregoing acknowledgements, representations and agreements.

9.3 Canada

The Shares may be sold in Canada only to purchasers resident or located in the Provinces of Ontario, Québec, Alberta and British Columbia, purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 *Prospectus Exemptions* or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 *Registration Requirements, Exemptions and Ongoing Registrant Obligations*. Any resale of the Shares must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this Prospectus (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 *Underwriting Conflicts* ("NI 33-105"), the Underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

9.4 Australia

This Prospectus does not constitute a prospectus or other disclosure document under the Corporations Act 2001 (Cth) ("**Australian Corporations Act**") and does not purport to include the information required of a disclosure document under the Australian Corporations Act. This Prospectus has not been, and will not be, lodged with the Australian Securities and Investments Commission (whether as a disclosure document under the Australian Corporations Act or otherwise). Any offer in Australia of the Shares under this Prospectus or otherwise may only be made to persons who are "sophisticated investors" (within the meaning of section 708(8) of the Australian Corporations Act), to "professional investors" (within the meaning of section 708(11) of the Australian Corporations Act) or otherwise pursuant to one or more exemptions under section 708 of the Australian Corporations Act so that it is lawful to offer the Shares in Australia without disclosure to investors under Part 6D.2 of the Australian Corporations Act.

Any offer for on-sale of the Shares that is received in Australia within 12 months after their issue by the Company is likely to need prospectus disclosure to investors under Part 6D.2 of the Australian Corporations Act, unless such offer for on-sale in Australia is conducted in reliance on a prospectus disclosure exemption under section 708 of the Australian Corporations Act or otherwise. Any persons acquiring Shares should observe such Australian on-sale restrictions.

The Company is not licensed in Australia to provide financial product advice in relation to the Shares. Any advice contained in this Prospectus is general advice only. This Prospectus has been prepared without taking account of any investor's objectives, financial situation or needs, and before making an investment decision on the basis of this Prospectus, investors should consider the appropriateness of the information in this Prospectus, having regard to their own objectives, financial situation and needs. No cooling off period applies to an acquisition of the Shares.

9.5 Japan

The Shares have not been and will not be registered under the Financial Instruments and Exchange Act of Japan (Act No. 25 of 1948, as amended; the FIEA). Neither the Shares nor any interest therein may be offered or sold, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or entity organised under the laws of Japan), or to others for reoffering or resale, directly or indirectly, in Japan or to, or for the benefit of, a resident of Japan except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the FIEA and any other applicable laws, regulations and ministerial guidelines of Japan.

9.6 Israel

This document does not constitute a prospectus under the Israeli Securities Law, 5728-1968, and has not been filed with or approved by the Israel Securities Authority. In Israel, this Prospectus is being distributed only to, and is directed only at, investors listed in the first addendum, to the Israeli Securities Law (the "**Addendum**"), consisting primarily of joint investment in trust funds; provident funds; insurance companies; banks; portfolio managers, investment advisors, members of the Tel Aviv Stock Exchange Ltd., underwriters, each purchasing for their own account; venture capital funds; entities with equity in excess of NIS 50 million and "qualified individuals," each as defined in the Addendum (as it may be amended from time to time), collectively referred to as "Qualified Israeli Investors". Qualified Israeli Investors shall be required to submit written confirmation that they fall within the scope of the Addendum.

9.7 Hong Kong

This Prospectus has not been approved by or registered with the Securities and Futures Commission of Hong Kong or the Registrar of Companies of Hong Kong. No person may offer or sell in Hong Kong, by means of any document, any Shares other than (i) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571) of Hong Kong and any rules made under that Ordinance, or (ii) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32) of Hong Kong or which do not constitute an offer to the public within the meaning of that Ordinance.

No person may issue or have in its possession for the purposes of issue, whether in Hong Kong or elsewhere, any advertisement, invitation or document relating to the Shares which is directed at, or the contents of which are

likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to Shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance and any rules made under that Ordinance.

9.8 Switzerland

The Shares may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("**SIX**") or on any other stock exchange or regulated trading facility in Switzerland.

The Prospectus has been prepared without regard to the disclosure standards for issuance prospectuses under article 652a or article 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under article 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither the Prospectus nor any other offering or marketing material relating to the Shares or the Global Offer may be publicly distributed or otherwise made publicly available in Switzerland.

Neither the Prospectus nor any other offering or marketing material relating to the Global Offer, the Company or the Shares has been or will be filed with, and the offer of the Shares will not be supervised by, the Swiss Finance Market Supervisory Authority FINMA, and the offer of the Shares has not been and will not be authorised under the Swiss Federal Act on Collective Investment Schemes ("**CISA**"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of the Shares.

9.9 Singapore

This Prospectus has not been and will not be registered as a prospectus with the Monetary Authority of Singapore and the securities will be offered pursuant to exemptions under the Securities and Futures Act, Chapter 289 of Singapore (the "**SFA**"). Accordingly, this Prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Shares may not be circulated or distributed, nor may the Shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (1) to an institutional investor under Section 27 4 of the SFA; (2) to a relevant person pursuant to Section 275(1) of the SFA, or any person pursuant to Section 275(1A) of the SFA, and in accordance with the conditions, specified in Section 275 of the SFA or (3) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the Shares are purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) (as defined in Section 4A of the SFA) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, securities (as defined in Section 239(1) of the SFA) of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the securities under Section 275 of the SFA except:

i. to an institutional investor or to a relevant person defined in Section 275(2) of the SFA or to any person arising from an offer referred to in Section 275(1A) or Section 276(4)(i)(B) of the SFA;

ii. where no consideration is or will be given for the transfer;

iii. where the transfer is by operation of law;

iv. as specified in Section 276(7) of the SFA;

v. or as specified in Regulation 32 of the Securities and Futures (Offers and Investments) (Shares and Debentures) Regulations 2005 of Singapore.

PART 16
ADDITIONAL INFORMATION

1. RESPONSIBILITY

The Company and the Directors accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Directors and the Company (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this Prospectus is in accordance with the facts and contains no omission likely to affect the import of such information.

2. INCORPORATION AND REGISTERED OFFICE

2.1 The Company was incorporated and registered in England and Wales on 8 May 2017 as a public company limited by shares under the Act with the name Energean Oil & Gas plc and with the registered number 10758801.

2.2 The Company's registered office and principal place of business is at 21 Gloucester Place, London, United Kingdom, W1U 8HR, and its telephone number is +44 20 3859 3540.

2.3 The principal laws and legislation under which the Company operates and the Shares will be issued are the Act and regulations made thereunder.

3. ISSUED SHARE CAPITAL

3.1 Issued share capital

The issued and fully paid up share capital of the Company, immediately prior to the publication of the Prospectus, and as it will be immediately following Admission, is as follows:

Class of share	Number of shares as of the date of this Prospectus	Number of shares immediately following Admission
Ordinary shares of £0.01 each	80,231,222	152,823,238

3.2 History of the share capital

3.2.1 On incorporation the share capital of the Company was £50,000 being 50,000 ordinary shares of £1.00. Since incorporation, there have been the following changes to the Company's issued share capital:

(i) On 30 June 2017, the Company undertook a share split, redesignating each ordinary share of £1.00 each into 100 Shares, increasing the number of issued Shares to 5,000,000 Shares.

(ii) On 30 June 2017, the Company issued 65,468,982 Shares to certain of the Existing Shareholders in consideration for the transfer of shares representing 99.7% of the issued share capital of Energean E&P Holdings to the Company. The Company has agreed to issue 174,138 Shares to HIL Hydrocarbon Investments Ltd and Capital Energy Investments Ltd in consideration for the transfer of shares representing the remaining 0.3% of the issued share capital of Energean E&P Holdings to the Company on the same terms as applied under the Reorganisation Agreement once the relevant shareholders are able to discharge certain security over their shares in Energean E&P Holdings. Pending such transfer, the shares in Energean E&P Holdings owned by HIL Hydrocarbon Investments Ltd and Capital Energy Investments Ltd are held on trust for the benefit of the Company.

(iii) On 15 March 2018 the Company acquired the EIL Preference Shares from Third Point in consideration for the issue of 9,270,038 Shares in aggregate (being the Acquisition Shares) to Third Point.

(iv) On 15 March 2018, the Company issued an aggregate of 492,202 Shares to (i) Simon Heale, Andrew Bartlett, Ohad Marani, Robert Peck and Karen Simon in payment of their fees as Directors from their respective date of appointment until 15 March 2018 and (ii) certain advisers in respect of their fees payable in respect of the Global Offer.

3.2.2 For details of the reorganisation undertaken by the Group in connection with Admission see "*Principal Shareholders and Related Party Transactions—Related Party Transactions—Reorganisation in connection with Admission*".

3.3 Other

3.3.1 Save as disclosed in this paragraph 3 and in paragraphs 8 and 10 below:

(i) no share or loan capital of the Company has, within three years of the date of this Prospectus, been issued or agreed to be issued, or is now proposed to be issued (other than pursuant to the Global Offer), fully or partly paid, either for cash or for a consideration other than cash, to any person;

(ii) no commissions, discounts, brokerages or other special terms have been granted by the Company in connection with the issue or sale of any share or loan capital of any such company;

(iii) no share or loan capital of the Company or any member of the Group is under option or agreed conditionally or unconditionally to be put under option;

(iv) there are no acquisition rights or obligations in relation to the issue of shares in the capital of the Company or any undertaking to increase the capital of the Company;

(v) there are no other convertible securities, exchangeable securities or securities with warrants in the Company; and

(vi) neither the Company, nor any member of the Group, holds any treasury shares in the Company.

3.3.2 The Company will be subject to the continuing obligations of the FCA with regard to the issue of shares for cash. The provisions of section 561(1) of the Act (which confer on shareholders rights of pre-emption in respect of the allotment of equity securities which are, or are to be, paid up in cash other than by way of allotment to employees under an employees' share scheme as defined in section 1166 of the Act) apply to the issue of shares in the capital of the Company except to the extent such provisions have been disapplied as referred to in paragraph 3.4 below.

3.3.3 Immediately following Admission, it is expected that at least 25% of the Company's issued ordinary share capital will be held in public hands (within the meaning of paragraph 6.14.1 of the Listing Rules).

3.4 Share capital authorities relating to the Global Offer

On 15 March 2018, the following ordinary and special resolutions were passed by the Company's shareholders:

(i) in addition to the authorities contained in sub-paragraphs (ii) and (iv) below, the Directors were generally and unconditionally authorised for the purpose of section 551 of the Act to exercise all the powers of the Company to allot Shares up to a maximum aggregate nominal amount of £92,700.38 in connection with the issue of the Acquisition Shares;

(ii) in addition to the authorities contained in sub-paragraph (iv) below, the Directors were generally and unconditionally authorised for the purpose of section 551 of the Act to exercise all the powers of the Company to allot Shares up to a maximum aggregate nominal amount of £738,483.34 in connection with the Global Offer, the Shares to be represented by the Admission Awards and the Shares to be issued to certain Directors in payment of their fees up to 15 March 2018 and certain advisers in respect of their fees payable in respect of the Global Offer;

(iii) in addition to the authorities contained in sub-paragraph (v) below, the Directors were empowered pursuant to section 570 of the Act to allot equity securities (within the meaning of section 560(1) of the Act) for cash pursuant to the authority conferred by sub-paragraph (ii) above as if section 561 of the Act did not apply to the allotment, provided that the power conferred by this resolution was limited to the allotment of up to 73,848,334 Shares in connection with the Global Offer, the Shares to be represented by the Admission Awards and the Shares to be issued to certain Directors in payment of their fees up to 15 March 2018 and certain advisers in respect of their fees payable in respect of the Global Offer;

(iv) subject to Admission, and in addition to the authorities set out in sub-paragraph (ii) above, the Directors were generally and unconditionally authorised for the purpose of section 551 of the Act to exercise all the powers of the Company to allot new Shares in the Company or to grant rights to subscribe for or to convert any security into new Shares in the Company:

(A) up to a maximum aggregate nominal amount of £509,410.79 (representing 50,941,079 Shares, which is less than one-third of the issued ordinary share capital of the Company at Admission); and

(B) in addition to the amount referred to in paragraph (ii) above, up to an aggregate nominal amount of £1,018,821.58 (representing 101,882,158 Shares) in relation to an allotment of equity securities (within the meaning of section 560(1) of the Act) in connection with a rights issue,

for a period expiring at the earlier of the conclusion of the Company's annual general meeting in 2018 and 30 June 2018. The aggregate amount in sub-paragraph (B) represents less than two-thirds of the issued ordinary share capital of the Company as of Admission and is consistent with the current guidance issued by the Investment Association;

(v) subject to Admission, and in addition to the authorities set out in sub-paragraph (iv) above, the Directors are empowered pursuant to section 570 of the Act to allot equity securities (within the meaning of section 560(1) of the Act) for cash:

(A) pursuant to the authority conferred by sub-paragraph (iv)(A) above as if section 561 of the Act did not apply to the allotment, provided that the power conferred by this resolution is limited to (I) an allotment of equity securities in connection with a pre-emptive offer or (II) an allotment of equity securities otherwise than in connection with a pre-emptive offer up to a nominal amount not exceeding in aggregate £76,411.61 (representing 7,641,161 Shares, which is less than 5% of the issued ordinary share capital of the Company at Admission), and

(B) pursuant to the authority given by the resolution referred to in sub-paragraph (iv)(B) above as if section 561 of the Act did not apply to the allotment provided that the power conferred by this resolution is limited to an allotment of equity securities in connection with a rights issue,

such power to expire at the earlier of the conclusion of the Company's annual general meeting in 2018 and 30 June 2018; and

(vi) the Company will be generally and unconditionally authorised to make market purchases (within the meaning of section 693(4) of the Act) of Shares each subject to the following conditions:

(A) the maximum aggregate number of Shares authorised to be purchased shall be 15,282,323, representing approximately 10% of the Company's issued ordinary share capital immediately following Admission;

(B) the minimum price (excluding expenses) which may be paid for each Share shall be one pence (being the nominal value of a Share);

(C) the maximum price (excluding expenses) which may be paid for each Share is the higher of: (I) 105% of the average of the middle market quotations for the Shares as derived from the London Stock Exchange Daily Official List for the five business days immediately preceding the day on which the share is contracted to be purchased; and (II) an amount equal to the higher of the price of the last independent trade of a Share and the highest current independent bid for a Share as derived from the London Stock Exchange Trading System; and

(D) the authority shall expire on the date falling 15 months after the resolution conferring it is passed or, if earlier, at the end of the next annual general meeting of the Company so that the Company may, before the expiry of the authority enter into a contract to purchase Shares which will or may be executed wholly or partly after the expiry of such authority.

4. ARTICLES OF ASSOCIATION

The Articles are available for inspection at the address specified below in paragraph 20 of this Part 16 "*—Documents available for inspection*".

The Articles of Association of the Company (the "**Articles**") include provisions to the following effect:

4.1 Share Rights

Subject to the provisions of the Act and without prejudice to any rights attached to any existing shares or class of shares, any share may be issued with such rights or restrictions as the Company may by ordinary resolution determine or, subject to and in default of such determination, as the Board shall determine.

Subject to the provisions of the Act and without prejudice to any rights attached to any existing shares or class of shares, the Board may issue shares which are to be redeemed or are liable to be redeemed at the option of the Company or the holder. Subject to the Articles and to the Act, all the shares for the time being in the capital of the Company are at the disposal of the Board.

4.2 Voting Rights

Subject to any rights or restrictions attached to any shares, and any rights or restrictions detailed in the notice of meeting, on a show of hands every shareholder who is present in person shall have one vote and on a poll every shareholder present in person or by proxy shall have one vote for every share of which he is the holder.

No shareholder shall be entitled to vote at any general meeting of the Company unless all moneys presently payable by him in respect of the shares in the Company have been paid.

If at any time the Board is satisfied that any shareholder, or any other person appearing to be interested in the shares held by such a shareholder, has been duly served with a notice under section 793 of the Act and

is in default for the prescribed period in supplying to the Company the information thereby required, or, in purported compliance with such a notice, has made a statement which is false or inadequate in a material particular, the Board may, in its absolute discretion at any time thereafter by notice to such shareholder, direct that, in respect of the shares in relation to which the default occurred, the shareholder shall not be entitled to attend or vote either personally or by proxy at a general meeting or at a separate meeting of the holders of that class of shares or on a poll.

4.3 Dividends and Other Distributions

Subject to the provisions of the Act, the Company may by ordinary resolution declare dividends in accordance with the respective rights of the shareholders, provided that no dividend shall exceed the amount recommended by the Board. Except as otherwise provided by the rights attached to shares, all dividends shall be declared and paid according to the amounts paid up on the shares on which the dividend is paid, but no amount paid on a share in advance of calls shall be treated for these purposes as paid on the share.

Subject to the provisions of the Act, the Board may pay interim dividends if it appears to the Board that they are justified by the profits of the Company available for distribution.

The Board may also pay, at intervals determined by it, any dividend at a fixed rate if it appears to the Board that the profits available for distribution justify the payment. Dividends may be declared and paid in any currency or currencies that the board shall determine. If the Board acts in good faith it shall not incur any liability to the holders of shares conferring preferred rights for any loss they may suffer by the lawful payment of an interim dividend on any shares having deferred or non-preferred rights.

No dividend or other moneys payable in respect of a share shall bear interest against the Company unless otherwise provided by the rights attached to the share.

If at any time the Board is satisfied that any shareholder, or any other person appearing to be interested in the shares held by such shareholder, has been duly served with a notice under section 793 of the Act and is in default for the prescribed period in supplying to the Company the information thereby required, or, in purported compliance with such a notice, has made a statement which is false or inadequate in a material particular, then the Board may, in its absolute discretion at any time thereafter, serve a direction notice on such shareholder and withhold payment from such shareholder of any dividend otherwise payable, if the relevant shares represent at least a 0.25% interest in the Company's shares or any class thereof.

The Board may, if authorised by an ordinary resolution of the Company, offer to any holder of shares the right to elect to receive shares, credited as fully paid, instead of cash in respect of the whole, or some part (to be determined by the Board), of any dividend.

Any dividend which has remained unclaimed for 12 years from the date when it became due for payment shall, if the Board so resolves, be forfeited and cease to remain owing by the Company.

A liquidator may, with the sanction of a special resolution and any other sanction required by the Insolvency Act 1986, divide among the shareholders in specie the whole or any part of the assets of the Company and may, for that purpose, value any assets and determine how the division shall be carried out as between the shareholders or different classes of shareholders.

4.4 Variation of Rights

Rights attached to any class of shares may be varied or abrogated with the written consent of the holders of three-quarters in nominal value of the issued shares of the class, or the sanction of a special resolution passed at a separate general meeting of the holders of the shares of the class.

4.5 Lien and Forfeiture

The Company shall have a first and paramount lien on every share (that is not a fully paid share) for all moneys payable to it (whether presently or not) in respect of that share. The Company may sell any share on which it has a lien if a sum in respect of which the lien exists is presently payable and is not paid within 14 clear days after notice has been sent to the holder of the share demanding payment and stating that if the notice is not complied with the share may be sold.

The Board may from time to time make calls on the shareholders in respect of any moneys unpaid on their shares. Each shareholder shall (subject to receiving at least 14 clear days' notice) pay to the

Company the amount called on his shares. If a call or any instalment of a call remains unpaid in whole or in part after it has become due and payable, the Board may give the person from whom it is due not less than 14 clear days' notice requiring payment of the amount unpaid together with any interest which may have accrued and any costs, charges and expenses incurred by the Company by reason of such non-payment. The notice shall name the place where payment is to be made and shall state that if the notice is not complied with the shares in respect of which the call was made will be liable to be forfeited.

4.6 Transfer of Shares

A shareholder may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any form which the Board may approve. An instrument of transfer shall be signed by or on behalf of the transferor and, unless the share is fully paid, by or on behalf of the transferee. An instrument of transfer need not be under seal. The transferor shall remain the holder of the shares concerned until the name of the transferee is entered in the register in respect of the shares.

All transfers which are in uncertificated form shall be effected by means of the relevant system unless the Uncertificated Securities Regulations 2001 (the "**CREST Regulations**") provide otherwise.

The Board may, in its absolute discretion, refuse to register the transfer of a certificated share which is not a fully paid share, provided that the refusal does not prevent dealings in shares in the Company from taking place on an open and proper basis. The Board may also refuse to register the transfer of a certificated share unless the instrument of transfer:

(a) is lodged, stamped (if stampable), at the office or at another place appointed by the Board, accompanied by the certificate for the share to which it relates and such other evidence as the Board may reasonably require to show the right of the transferor to make the transfer;

(b) is in respect of one class of share only; and

(c) is in favour of not more than four persons.

If the Board refuses to register a transfer of a share in certificated form, it shall send the transferee notice of its refusal within two months after the date on which the instrument of transfer was lodged with the Company.

No fee shall be charged for the registration of any instrument of transfer or other document relating to or affecting the title to a share.

Subject to the provisions of the CREST Regulations, the Board may permit the holding of shares in any class of shares in uncertificated form and the transfer of title to shares in that class, by means of a relevant system and may determine that any class of shares shall cease to be a participating security.

If a notice is given to a shareholder in respect of a share, which is subsequently transferred, a person entitled to that share is bound by the notice if it was given to the shareholder before the person entitled to that share was entered into the register as the holder of that share.

4.7 General Meetings

The Board shall convene and the Company shall hold general meetings as annual general meetings in accordance with the requirements of the Act. The Board may call general meetings whenever and at such times and places as it shall determine.

Pursuant to a special resolution passed on 15 March 2018, the Company will be authorised in accordance with the Articles, until the Company's next annual general meeting, to call general meetings on 14 clear days' notice.

4.8 Directors

Appointment of Directors

Unless otherwise determined by ordinary resolution, the number of Directors shall be not less than two but shall not be subject to any maximum in number. Directors may be appointed by ordinary resolution of shareholders at a general meeting, by the Board or, if there is only one Director, by such Director.

No Share Qualification

A Director shall not be required to hold any shares in the capital of the Company by way of qualification.

Retirement of Directors

At every annual general meeting all the Directors appointed by the Board or, if there is only one Director, by such Director at the date of the notice convening the annual general meeting shall retire from office. If the Company does not fill the vacancy at the meeting at which a director retires, the retiring director shall be deemed to have been re-appointed unless at the meeting it is resolved not to fill the vacancy or unless a resolution for the re-appointment of the director is put to the meeting and lost.

Remuneration of Directors

The emoluments of any Director holding executive office for his services as such shall be determined by the Board, and may be of any description.

The ordinary remuneration of the Non-Executive Directors for their services (excluding amounts payable under any other provision of these Articles) shall be such amount as the Board may from time to time determine. Subject thereto, each such Director shall be paid a fee (which shall be deemed to accrue from day to day) at such rate as may from time to time be determined by the Board. In addition, any Non-Executive Director who performs special services which in the opinion of the Board are outside the scope of the ordinary duties of a Director may be paid such extra remuneration as the Board may determine.

In addition to any remuneration to which the Directors are entitled under the Articles, they may be paid all travelling, hotel and other expenses properly incurred by them in connection with their attendance at meetings of the Board or committees of the Board, general meetings or separate meetings of the holders of any class of shares or of debentures of the Company or otherwise in connection with the discharge of their duties.

The Board may provide benefits, whether by the payment of gratuities or pensions or by insurance or otherwise, for any past or present Director or employee of the Company or any of its subsidiary undertakings or any body corporate associated with, or any business acquired by, any of them, and for any shareholder of his family or any person who is or was dependent on him.

Permitted Interests of Directors

Subject to the provisions of the Act, and provided that he has disclosed to the Board the nature and extent of his interest, a Director, notwithstanding his office:

(a) may be a party to, or otherwise interested in, any transaction or arrangement with the Company in which the Company is otherwise interested;

(b) may act by himself or his firm in a professional capacity for the Company (otherwise than as auditor), and he or his firm shall be entitled to remuneration for professional services as if he were not a Director;

(c) may hold any office or place of profit with the Company (otherwise than as auditor) in conjunction with his office of director for such period and upon such terms, including as to remuneration as the board may decide;

(d) may be a director or other officer of, or employed by, or a party to any transaction or arrangement with, or otherwise interested in, any body corporate in which the Company is (directly or indirectly) interested as shareholder or otherwise or with which he has such a relationship at the request or direction of the Company; and

(e) shall not, by reason of his office, be accountable to the Company for any benefit which he derives from any such office or employment, or from any such transaction or arrangement, or from any interest in any such body corporate if the acceptance, entry into or existence of which has been approved by the Board or properly disclosed and no such transaction or arrangement shall be liable to be avoided on the ground of any such interest or benefit.

Restrictions on Voting

A Director shall not vote on any resolution of the Board concerning a matter in which he has an interest which can reasonably be regarded as likely to give rise to a conflict with the interests of the Company, but these prohibitions shall not apply to:

(a) the giving of a guarantee, security or indemnity in respect of money lent or obligations incurred by him or any other person at the request of, or for the benefit of, the Company or any of its subsidiary undertakings;

(b) the giving of a guarantee, security or indemnity in respect of a debt or obligation of the Company or any of its subsidiary undertakings for which the Director has assumed responsibility (in whole or part and whether alone or jointly with others) under a guarantee or indemnity or by the giving of security;

(c) a contract, arrangement, transaction or proposal concerning an offer of shares, debentures or other securities of the Company or any of its subsidiary undertakings for subscription or purchase, in which offer he is or may be entitled to participate as a holder of securities or in the underwriting or sub-underwriting of which he is to participate;

(d) a contract, arrangement, transaction or proposal concerning any other body corporate in which he or any person connected with him is interested, directly or indirectly, and whether as an officer, shareholder, creditor or otherwise, if he and any persons connected with him do not to his knowledge hold an interest (as that term is used in sections 820 to 825 of the Act) representing 1% or more of either any class of the equity share capital of such body corporate (or any other body corporate through which his interest is derived) or of the voting rights available to shareholders of the relevant body corporate (any such interest being deemed to be a material interest in all circumstances);

(e) a contract, arrangement, transaction or proposal for the benefit of employees of the Company or of any of its subsidiary undertakings which does not award him any privilege or benefit not generally accorded to the employees to whom the arrangement relates;

(f) a contract, arrangement, transaction or proposal concerning any insurance which the Company is empowered to purchase or maintain for, or for the benefit of, any Directors or for persons who include Directors; and

(g) a contract relating to a pension, superannuation or similar scheme or a retirement, death, disability benefits scheme or employees' share scheme which gives the director benefits which are also generally given to the employees to whom the scheme relates.

Borrowing Powers

The Board may exercise all the powers of the Company to borrow money, to guarantee, to indemnify, to mortgage or charge its undertaking, property, assets (present and future) and uncalled capital, and to issue debentures and other securities whether outright or as collateral security for any debt, liability or obligation of the Company or of any third party.

Indemnity of Officers

Subject to the provisions of the Act, but without prejudice to any indemnity to which the person concerned may otherwise be entitled, every Director or other officer of the Company shall be indemnified out of the assets of the Company against any liability incurred by him for negligence, default, breach of duty or breach of trust in relation to the affairs of the Company, or any associated company, and any other liability incurred by or attaching to him in relation to or in connection with his duties, powers or office, including in connection with the activities of the Company or an associated company in its capacity as a trustee of an occupational pension scheme but this shall not apply to any liability owed to the Company or associated company and shall not provide for or entitle any such person to indemnification to the extent that it would cause this provision, or any element of it, to be treated as void under the Act. This indemnity shall extend to all costs, changes, losses, expense and liabilities incurred by him in relation thereto.

5. MANDATORY BIDS AND COMPULSORY ACQUISITION RULES RELATING TO ORDINARY SHARES

Other than as provided by the City Code and Chapter 28 of the Act, there are no rules or provisions relating to mandatory bids and/or squeeze out and sell out rules relating to the Company.

5.1 Mandatory bid

The City Code applies to the Company. Under the City Code, if an acquisition of interests in shares, whether by a series of transactions over time or not, were to increase the aggregate holding of the acquirer and its concert parties to interests in shares carrying 30% or more of the voting rights in the Company, the acquirer and, depending on the circumstances, its concert parties would be required (except with the consent of the Takeover Panel) to make a cash offer for the outstanding shares in the Company at a price

not less than the highest price paid for interests in shares by the acquirer or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of interests in shares by a person holding (together with its concert parties) shares carrying between 30% and 50% of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the total voting rights in the Company.

The Founders, who collectively are interested in approximately 27% of the issued share capital of the Company, are deemed to be acting in concert with each other for the purposes of the City Code.

5.2 Squeeze-out

Under the Act, if an offeror were to make an offer to acquire all of the shares in the Company not already owned by it and were to acquire 90% of the shares to which such offer related it could then compulsorily acquire the remaining 10% of the Shares. The offeror would do so by sending a notice to outstanding shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would deliver a transfer of the outstanding shares in its favour to the Company which would execute the transfers on behalf of the relevant shareholders, and pay the consideration to the Company which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose shares are compulsorily acquired under this procedure must, in general, be the same as the consideration that was available under the original offer unless a shareholder can show that the offer value is unfair.

5.3 Sell-out

The Act also gives minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the shares in the Company and, at any time before the end of the period within which the offer could be accepted, the offeror held or had agreed to acquire not less than 90% of the shares, any holder of shares to which the offer related who had not accepted the offer could by a written communication to the offeror require it to acquire those shares. The offeror would be required to give any shareholder notice of his/her right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or, if later, three months from the date on which notice is served on shareholders notifying them of their sell-out rights. If a shareholder exercises his/her rights, the offeror is entitled and bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

6. DIRECTORS' AND SENIOR MANAGERS' INTERESTS

6.1 The interests in the share capital of the Company of the Directors and Senior Managers (all of which, unless otherwise stated, are beneficial or are interests of a person connected with a Director or a Senior Manager) as of the Latest Practicable Date together with the interests, which are expected immediately following Admission, are set out in the following table:

	Immediately prior to Admission		Immediately following Admission	
Director / Senior Manager	**Number of Shares**	**Percentage of issued share capital**	**Number of Shares**	**Percentage of issued Share Capital**
Simon Heale	9,233	0.0%	21,978	0.0%
Mathios Rigas[(1)]	18,688,224	23.3%	19,437,816	12.7%
Efstathios Topouzoglou[(2)]	16,281,257	20.3%	17,819,893	11.7%
Panos Benos[(3)]	3,976,809	5.0%	4,055,713	2.7%
Andrew Bartlett	2,126	0.0%	2,126	0.0%
David Bonanno	—	—	—	—
Robert Peck	2,690	0.0%	2,690	0.0%
Ohad Marani	2,690	0.0%	2,690	0.0%
Karen Simon	2,037	0.0%	89,949	0.1%
Dr Stephen Moore	—	—	—	—
James Efstathiou	—	—	—	—
David Donaldson	—	—	—	—
Fred Riddiford	—	—	—	—

Notes:

(1) Number of shares shown represents the aggregate shareholding of Mathios Rigas as an individual and his indirect holdings by virtue of his controlling interest in Growthy Holdings Co. Limited and Capital Energy Investments Ltd, a company controlled by Mathios Rigas. In addition, Capital Energy Investments Ltd has a conditional interest in 82,488 Shares, which will be issued by the Company upon the transfer of certain shares in Energean E&P Holdings on the terms of the Reorganisation Agreement. See also paragraph 3.1 of Part 9 "*Principal Shareholders and Related Party Transactions*".

(2) Number of shares shown represents the aggregate shareholding of Efstathios Topouzoglou as an individual and his indirect holdings by virtue of his controlling interest in Oilco Investments Limited and HIL Hydrocarbon Investments Ltd, a company controlled by Efstathios Topouzoglou. In addition, HIL Hydrocarbon Investments Ltd has a conditional interest in 91,650 Shares, which will be issued by the Company upon the transfer of certain shares in Energean E&P Holdings on the terms of the Reorganisation Agreement. See also paragraph 3.1 of Part 9 "*Principal Shareholders and Related Party Transactions*".

(3) Number of shares shown represents the aggregate shareholding of Panos Benos as an individual and his indirect holdings by virtue of his controlling interest in Adobelero Holdings Co. Ltd.

6.2 Save as disclosed in paragraph 3.2 of Part 9 "*Principal Shareholders and Related Party Transactions*", no Director has or has had any interest in any transactions which are or were unusual in their nature or conditions or are or were significant to the business of the Group or any of its subsidiary undertakings and which were effected by the Group or any of its subsidiaries during the current or immediately preceding financial year or during an earlier financial year and which remain in any respect outstanding or unperformed.

6.3 There are no outstanding loans or guarantees granted or provided by any member of the Group to or for the benefit of any of the Directors.

6.4 No Director or Senior Manager has any potential conflict of interest between his or her duties to the Company and his or her private interests or other duties.

6.5 Directors' and Senior Managers' current and past directorships and partnerships

Set out below are the directorships and partnerships held by the Directors and Senior Managers (other than, where applicable, directorships held in the Company and/or any other company in the Group), in the five years prior to the date of this Prospectus:

Name	Current directorships / partnerships	Past directorships
Simon Heale	Marex Spectron Gulf Marine Services	Kaz Minerals plc Morgan Advanced Materials PZ Cussons plc Coats plc
Mathios Rigas	N/A	Capital Connect Venture Managers S.A. Zinais Real Estate Development S.A. MAVIN S.A. Tyres Herco S.A. Capital Connect Limited (Greece) Agriculture-livestock-Commercial-Real Estate Ilion S.A. (Greece)
Panos Benos	Dunworth Mews Limited OKTO Energy Limited Colville Square Mews Management Company Limited	N/A
Andrew Bartlett	Pegasus Capital Investment Ltd. Africa Oil Corporation Impact Oil&Gas Limited Bartlett Energy Advisers Limited	Camelot Foods Limited Azonto Petroleum Ltd. Eland Oil and Gas Ltd. The Petroleum and Renewable Energy Company Limited
Efstathios Topouzoglou	Prime Technologia Energeias Kai Perivallontos S.A. Prime Green Chartofylakiou S.A. Jet Ktimatiki S.A. Investland Corporation FSL Holdings Pte. Ltd. FSL Asset Management Pte. Ltd. FSL Trust Management Pte. Ltd	N/A
David Bonanno	Hellenic Bank PCL Cyprus Social Finance Inc. USA Neptune Finance Inc. USA	N/A
Robert Peck	N/A	N/A
Ohad Marani	Bank Leumi of Israel Ltd Israel Infrastructure Fund Tadbik Ltd.	ILDC Energy Ltd. Emmanuelle Energy Nisko Electricity and Electronics Ltd.
Karen Simon	Aker ASA	N/A
Dr. Stephen Moore	5MD Oil and Gas Consultants Ltd.	Petrofac Emirates (as Mubadala Board representative) Tatweer Petroleum (as Mubadala representative on the Operating Committee) NCo (as Mubadala Board member)
James Efstathiou	N/A	N/A
David Donaldson	Argyll Engineering Ltd. Donaldson & Sons, Agricultural Partnership	HCIA Ltd.
Fred Riddiford	N/A	N/A

6.6 Except as described in paragraphs 15.3 and 15.4 of this Part 16 "*Additional Information*", within the period of five years preceding the date of this Prospectus, none of the Directors:

6.6.1 has had any convictions in relation to fraudulent offences;

6.6.2 has been a member of the administrative, management or supervisory bodies or director or senior manager (who is relevant in establishing that a company has the appropriate expertise and experience for management of that company) of any company at the time of any bankruptcy, receivership or liquidation of such company; or

6.6.3 has received any official public incrimination and/or sanction by any statutory or regulatory authorities (including designated professional bodies) or has ever been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of a company or from acting in the management or conduct of affairs of a company.

7. DIRECTORS' TERMS OF EMPLOYMENT

7.1 The Directors and their functions are set out in Part 8 "*Directors, Senior Managers and Corporate Governance*".

7.2 Executive Directors

7.2.1 General

Mr Rigas and Mr Benos were appointed as directors of the Company on incorporation. The appointment of each of the Executive Directors will continue until the Company's first annual general meeting and their ongoing appointment is subject to being re-elected as a director at that meeting and at each subsequent annual general meeting. The Company, or the relevant Executive Director, may terminate the appointment of that Executive Director at any time upon six month's written notice, or an Executive Director may be required to resign at any time in accordance with the Articles or for any regulatory reason such as the revocation of any approvals required from the United Kingdom Listing Authority.

The Executive Directors are subject to certain restrictive covenants during the term of their executive service contract and, with respect to the undertaking not to disclose or use confidential information, at any time thereafter. The Executive Directors are not permitted to take up any office or employment with, or have any direct or indirect interest in any firm or company which is in direct or indirect competition with the Company or any other member of the Group or any company in which any member of the Group has an interest, without the consent of the Board. Their executive service contract also contains provisions relating to share dealings and a general non-competition covenant in relation to the Group for six months from the date of termination of the relevant executive service contract.

The Company's remuneration strategy is to provide pay packages that will:

- motivate and retain industry leading employees;
- attract high quality individuals to join the Company;
- encourage and support a high performance culture;
- reward delivery of the Company's business plan and key strategic goals; and
- align employees with the interests of shareholders and other external stakeholders.

Consistent with the remuneration strategy, the Remuneration Committee has agreed a post Admission remuneration policy for the Executive Directors, whereby:

- salaries will be set at competitive, but not excessive, levels compared to peers and other companies of an equivalent size and complexity;
- performance-related pay, based on stretching targets, will form a significant part of remuneration packages;
- there will be an appropriate balance between rewards for delivery of short-term and longer-term performance targets.

The remuneration framework intended to deliver this policy post Admission for the Executive Directors, will be a combination of base salary, benefits, an annual bonus (as described in paragraph 7.2.4) and awards under the LTIP as described in paragraph 8.2.

Each Executive Director's remuneration arrangements will be reviewed at least annually and assessed taking into account the scope and requirements of the role, experience of the incumbent and the total remuneration package. Account will also be taken of remuneration arrangements in peer companies and the wider employee group.

Executive Directors will be subject to share ownership guidelines that will require them to build up and retain a holding of Ordinary Shares worth 200% of their salary. Until a Director has satisfied their guideline, they will be required to retain at least 50% of vested share awards (after selling sufficient Ordinary Shares to satisfy tax liabilities upon vesting).

The Company will be required to submit its remuneration policy (as it relates to the Directors) to a binding vote of Shareholders at the Company's 2019 annual general meeting. Accordingly, the Company will outline its future policy relating to the Directors' remuneration in its Report and Accounts for its financial year ending 31 December 2018.

7.2.2 Mathios Rigas

In addition to his appointment as an Executive Director of the Company, Mr Rigas was appointed as chief executive officer of the Company under an executive service contract with the Company dated 20 February 2018. His period of appointment with the Company is deemed to have commenced on 11 July 2017. Following Admission, Mr Rigas will receive a salary of £675,000 per annum and a benefits package worth £75,000 per annum. The previous service contract between Mr Rigas and Energean E&P Holdings was terminated and replaced by this executive service contract.

7.2.3 Panos Benos

In addition to his appointment as an Executive Director of the Company, Mr Benos was appointed as chief financial officer of the Company under an executive service contract with the Company dated 20 February 2018. His period of appointment with the Company is deemed to have commenced on 11 July 2017. Following Admission, Mr Benos will receive a salary of £450,000 per annum and a benefits package worth £50,000 per annum. The previous service contract between Mr Benos and Energean E&P Holdings was terminated and replaced by this executive service contract.

7.2.4 Annual bonus

Annual bonuses for the Executive Directors for the financial years ending 31 December 2017 and 31 December 2018 will be determined by a combination of financial, strategic and operational Company measures and performance measures appropriate to an individual's role.

A cap on the maximum annual bonus opportunity will be introduced for the financial year ending 31 December 2018 of 150% of salary for the Executive Directors.

At least one-third of any annual bonus earned by the Executive Directors for the financial year ending 31 December 2018 will be deferred into awards over Ordinary Shares under the DBP which is summarised in paragraph 8.3 with such awards usually vesting two years post grant. Annual bonuses for the financial year ending 31 December 2017 will be paid wholly in cash.

7.3 Non-Executive Directors

7.3.1 The appointment of each of the Non-Executive Directors commenced as follows and will continue until the Company's first annual general meeting.

Name	Position	Date of Appointment
Simon Heale	Non-Executive Chairman	11 July 2017(1)
Andrew Bartlett	Senior Independent Director	22 August 2017
Efstathios Topouzoglou . .	Non-Executive Director	8 May 2017
David Bonanno	Non-Executive Director	8 May 2017
Robert Peck	Independent Non-Executive Director	11 July 2017
Ohad Marani	Independent Non-Executive Director	11 July 2017
Karen Simon	Independent Non-Executive Director	15 September 2017

Notes:

(1) Payment of fees commenced from 22 August 2017.

Each appointment is for an unlimited term, subject to being re-elected as a director at each annual general meeting, save that a Non-Executive Director or the Company may terminate the appointment at any time upon three months' written notice, or the Non-Executive Director may be required to resign at any time in accordance with the Articles, the UK Corporate Governance Code or for any regulatory reason such as the revocation of any approvals required from the UKLA. These appointments are otherwise subject to the provisions of the Articles and the terms of reference of the Board committees.

The Non-Executive Directors are subject to certain restrictive covenants during the appointment and, with respect to the undertaking not to disclose or use confidential information, at any time thereafter. The relevant agreements contain provisions relating to confidentiality, share dealings and conflicts of interest. The Non-Executive Directors are required to devote sufficient time to the affairs of the Company as is necessary to perform their respective duties. The Non-Executive Directors are not permitted to take up any office or employment with, or have any direct or indirect interest in any firm or company which is in direct or indirect competition with the Company or any other member of the Group or any company in which any member of the Group has an interest, without the consent of the Board. Upon termination of the appointment, and where such termination is for any reason other than due to the Non-Executive Director's gross misconduct, material breach of the terms of the appointment, act of fraud or dishonesty or wilful neglect of the Non-Executive Director's duties, the Non-Executive Director will be paid a pro-rated amount of his fees in respect of the period between the beginning of the quarter in which termination took place and the termination date. Otherwise, none of the Non-Executive Directors is entitled to any damages for loss of office and no fee shall be payable in respect of any unexpired portion of the term of the appointment.

7.3.2 Chairman

Mr. Heale was appointed as a Non-Executive director of the Company under letter of appointment for non-executive director chairman. Mr. Heale is entitled to an annual fee of £150,000, payable monthly and variable by agreement from time to time.

7.3.3 Non-Executive Directors

The other Non-Executive Directors, excluding David Bonanno, were entitled to a fee of £20,000 per annum apportioned pro rata from the date of commencement as a Director until the date of Admission. Each of Efstathios Topouzoglou, Robert Peck, Ohad Marani and Karen Simon are thereafter entitled to an annual fee of £50,000, payable monthly and variable by agreement from time to time. Mr. Bartlett is entitled to an annual fee of £57,500, payable monthly and variable by agreement from time to time for serving as Senior Independent Director. Mr. Bonanno has waived his entitlement to an annual fee for his services as a Director.

Andrew Bartlett, Ohad Marani and Robert Peck shall receive an additional annual fee of £5,000 for each Committee that they chair.

Karen Simon has agreed that following Admission her annual fees shall be payable by the issue of new Shares by the Company, rather than in cash. The number of Shares to be issued by the Company shall be equal to the fees for the preceding quarter divided by the average closing price of the Shares on the London Stock Exchange for the last 10 business days in the relevant quarter.

Each of Simon Heale, Andrew Bartlett, Ohad Marani, Robert Peck and Karen Simon has agreed to receive his or her remuneration accrued (net of tax) from the Company from the time of appointment through 15 March 2018 in the form of Shares, rather than cash, to be issued at the Offer Price. The disposal of any Shares by any Director will be subject to the Company's code on dealings in securities and the lock-up restrictions set out in Part 15 "*Details of the Global Offer*".

7.4 Each of Mathios Rigas (acting via Growthy Holdings), Efstathios Topouzoglou (acting via Oilco Investments), Panos Benos (acting via Adobelero), Simon Heale and Karen Simon has agreed to acquire an aggregate number of 2,467,789 Shares at Admission at the Offer Price. These Shares will be excluded from the Global Offer for purposes of calculation of the Underwriters' commissions pursuant to the Underwriting Agreement. The disposal of any Shares by any Director will be subject to the Company's code on dealings in securities and the lock-up restrictions set out in Part 15 "*Details of the Global Offer*".

7.5 Save as set out in paragraphs 7.2 and 7.3 above, there are no existing or proposed service agreements or letters of appointment between the Directors and any member of the Group.

7.6 Directors' and Senior Managers' remuneration and benefits

Under the terms of their service contracts for the year ended 31 December 2016, the aggregate remuneration paid (including contingent or deferred compensation) and benefits granted to the Directors and the Senior Managers, was £2.2 million.

Under the terms of their service contracts for the year ended 31 December 2016, the Directors were remunerated as set out below:

Name	Position	Annual remuneration: salary (£)	Annual remuneration: bonus (£)	Other benefits (£)	Total remuneration (£)
Simon Heale	Non-Executive Chairman	—	—	—	—
Mathios Rigas	CEO	913,693	—	—	913,693
Panos Benos	CFO	404,844	401,840	—	806,684
Andrew Bartlett	Senior Independent Director	—	—	—	—
Efstathios Topouzoglou	Non-Executive Director	—	—	—	—
David Bonanno	Non-Executive Director	—	—	—	—
Robert Peck	Independent Non-Executive Director	—	—	—	—
Ohad Marani	Independent Non-Executive Director	—	—	—	—
Karen Simon	Independent Non-Executive Director	—	—	—	—

7.7 There is no arrangement under which any Director has waived or agreed to waive future emoluments nor has there been any waiver of emoluments during the financial year immediately preceding the date of this Prospectus.

8. EMPLOYEE SHARE PLANS

8.1 Following Admission, the Company intends to operate an executive long-term incentive plan ("**LTIP**") and a deferred bonus plan under which a portion of annual bonuses may be deferred into Shares ("**DBP**"). Together the LTIP and DBP are referred to as the "Share Plans".

The principal features of the Share Plans are summarised below, with the common terms of the Share Plans set out in paragraph 8.4 below.

8.2 LTIP

It is currently intended that an LTIP award will be granted to the Executive Directors during 2018 over Shares worth 200% of salary. Performance conditions for this award will be determined by the Remuneration Committee at the time of grant and will be disclosed in the Annual Report for the financial year ending 31 December 2018. The LTIP award granted to the Executive Directors in 2018 will be subject to a three year performance period and two year holding period. Selected other senior executives will also receive LTIP awards in 2018.

Status

The LTIP was adopted by the Board on 2 March 2018, conditional on Admission. The LTIP is a discretionary executive share plan, under which the Board may grant share-based awards ("**LTIP Awards**") to incentivise and retain eligible employees. The LTIP will be administered by the Board or by any duly authorised committee of it. Decisions in relation to any participation in the LTIP by the Company's Executive Directors will always be taken by the Company's Remuneration Committee.

Individual limit

Awards will not normally be granted to a participant under the LTIP in respect of any financial year of the Company over Shares with a market value (as determined by the Board) in excess of 200% of salary. Awards may be granted in excess of this limit to an eligible employee in association with their recruitment (a "**Recruitment Award**"). Recruitment Awards may only be granted to an employee on one occasion.

Performance conditions

The vesting of LTIP Awards may (and, in the case of an LTIP Award to an Executive Director other than a Recruitment Award, will) be subject to the satisfaction of performance conditions. At least 50% of the performance conditions applicable to the initial LTIP Awards proposed to be granted to the Executive Directors will be based on relative total shareholder return ("TSR").

Any performance condition may be amended or substituted if one or more events occur which cause the Board to consider that an amended or substituted performance condition would be more appropriate and would not be materially less difficult to satisfy. The Board may also impose other conditions on the vesting of LTIP Awards.

Vesting, exercise and release of Awards

LTIP Awards subject to performance conditions will normally have those conditions assessed as soon as reasonably practicable after the end of the relevant performance period, and, to the extent that the performance conditions have been met, the LTIP Awards will vest either on that date or such later date that the Board determines. LTIP Awards (other than Recruitment Awards) granted to the Executive Directors will normally be subject to a performance period of at least three years and will only be capable of being satisfied in cash. LTIP Awards (other than Recruitment Awards) that are not subject to performance conditions will normally vest on the third anniversary of the grant date or such other date that the Board determines.

The Board may determine that an LTIP Award is also subject to an additional holding period of up to two years following vesting, during which Shares subject to the LTIP Award will not be delivered to participants and at the end of which the Awards will be "released".

Nil-cost options will normally be exercisable from the point of vesting (or, where the LTIP Award is subject to a holding period, release) until the tenth anniversary of the grant date.

8.3 The DBP

Status

The DBP was adopted by the Board on 2 March 2018, conditional on Admission. The DBP is a discretionary executive share plan implemented so that a portion of a participant's bonus is deferred into a share-based award (a "**DBP Award**"). The DBP will be administered by the Board or by any duly authorised committee of it. Decisions in relation to any participation in the DBP by the Company's Executive Directors will always be taken by the Company's Remuneration Committee.

Vesting of DBP Awards

DBP Awards will normally vest on the second anniversary of the grant date or such other date that the Board determines.

Nil-cost options will normally be exercisable from the point of vesting until the tenth anniversary of the grant date or, in the case of a DBP Award granted to a former employee, six months after the normal vesting date.

8.4 Terms common to the Share Plans

Eligibility

All employees (including Executive Directors) (and, in the case of the DBP, former employees) of the Company or any of its subsidiaries are eligible for selection to participate in the Share Plans at the discretion of the Board.

Timing of Awards

LTIP and DBP Awards (together, "**Awards**") can only be granted during the 42 days beginning on: (i) Admission; (ii) the first dealing day after the announcement of the Company's results for any period; (iii) any day on which the Board determines that exceptional circumstances exist which justify the making of an Award at that time; or (iv) to the extent that dealing restrictions prevent Awards from being granted in any of the preceding three periods, the first dealing day on which such dealing restrictions are lifted.

Form of Awards

The Board may grant Awards as conditional awards of Shares, nil-cost options over Shares or as conditional cash awards or options to acquire a cash amount which relates to the value of a certain number of notional Shares (a "**phantom award**"). If the Board grants Awards as phantom awards, it may reserve the right to convert these into conditional awards of Shares or nil-cost options over Shares at any time. No payment is required for the grant of an Award.

Overall limit

The Share Plans may operate over new issue Shares, treasury Shares or Shares purchased in the market. The rules of the Share Plans provide that, in any ten year rolling period, the number of Shares which may be issued under the Share Plans and any other employee share plan adopted by the Company may not exceed 10% of the issued ordinary share capital of the Company from time to time.

Shares transferred out of treasury will count towards this limits for so long as this is required under institutional shareholder guidelines. Shares issued or to be issued pursuant to Awards granted before or in respect of Admission (including the Admission Awards, as defined in paragraph 8.5 below) will not count towards this limit. In addition, Awards which are relinquished or lapse will be disregarded for the purposes of this limit.

Settlement

At its discretion, the Board may (unless the Board has determined otherwise at an earlier point) decide to satisfy Awards with a cash payment equal to the market value of the Shares that the participants would have received had the relevant Award been satisfied with Shares.

Dividend equivalents

The Board may decide that participants will receive an amount (in cash and/or additional Shares) equal in value to any dividends that would have been paid on the Shares which vest on such terms and over such period (ending no later than the date on which the Award vests or, if there is a holding period, is released) as the Board may determine. This amount may assume the reinvestment of dividends and exclude or include special dividends.

Malus and clawback

In certain circumstances the Board may at any time prior to the fifth anniversary of the grant date of an LTIP Award or the third anniversary of the grant date of a DBP Award:

(i) reduce an Award (to zero if appropriate) or impose additional conditions on an Award to the extent that cash and/or Shares have not yet been delivered in satisfaction of the Award; or

(ii) if cash and/or Shares have been delivered in satisfaction of an Award, require that the participant either return some or all of the Shares acquired pursuant to the Award or make a cash payment to the Company in respect of the Shares delivered.

The Board will retain the discretion to calculate the amount subject to recovery, including whether or not to claw back gross or net of any tax or social security contributions applicable to the Award.

The circumstances in which the Board may invoke the malus and clawback provisions include a material misstatement of the Company's audited accounts or any other error that would have reduced the grant or

vesting level of an Award, serious reputational damage, serious misconduct by a participant, or a material failure of risk management:

(i) in respect of LTIP Awards, during the period commencing on the grant date (or, where an LTIP Award is subject to a performance condition, at the start of the performance period) and ending on the fifth anniversary of the grant date; and

(ii) in respect of DBP Awards, during the period commencing at the start of financial year in respect of which the DBP Award is granted and ending on the third anniversary of the grant date.

Cessation of employment

An unvested Award will usually lapse upon a participant ceasing to be employed by or to hold office with the Group. However, if a participant ceases to be a Group employee or director because of their ill-health, injury, disability, redundancy, the sale of the participant's employing company or business out of the Group or in other circumstances at the discretion of the Board (except where they are dismissed for gross misconduct), their Award will normally continue to vest (and be released) on the date when it would have vested (and been released) if they had not ceased to be a Group employee or director, taking into account the satisfaction of any performance conditions applicable to LTIP Awards measured over the original performance period. However, the Board retains discretion to allow the Award to vest (and be released) following the individual's cessation of office or employment, taking into account any applicable performance conditions measured up to that point. Unless the Board decides otherwise, vesting of an LTIP Award will take into account the proportion of the vesting period (or, in the case of an Award subject to performance conditions, the performance period) which has elapsed on the participant's cessation of office or employment. A DBP Award will vest in full.

If a participant dies, unless the Board decides otherwise, their Award will vest (and be released) as soon as reasonably practicable after the date of their death on the basis set out for other "good leavers" above.

If a participant ceases to be an officer or employee of the Group during a holding period, their LTIP Award will normally be released at the end of the holding period, unless the Board determines that it should be released as soon as reasonably practicable after cessation of their office or employment. If a participant dies during the holding period, their LTIP Award will be released as soon as reasonably practicable after their death. If a participant is dismissed for gross misconduct, any outstanding LTIP Awards they hold will lapse immediately.

Awards structured as nil-cost options may normally be exercised to the extent vested for a period of six months after vesting (or, where LTIP Awards are subject to a holding period, release) or 12 months after death (or such other period as the Board may determine). Where nil-cost value options have already vested (and, where relevant, been released) on the date of cessation of office or employment, those options may normally be exercised for a period of six months from the date of cessation, unless the participant is dismissed for gross misconduct, in which case their options will lapse. If a participant dies, a vested (and, where relevant, released) option may normally be exercised until the first anniversary of the death.

Corporate events

In the event of a change of control of the Company, Awards will vest (and be released) early. The proportion of any unvested LTIP Awards which vest will be determined by the Board taking into account the extent to which any performance conditions applicable to LTIP Awards have been satisfied at that time and, unless the Board determines otherwise, the proportion of the vesting period, or in case of LTIP Awards subject to performance conditions, the performance period, which has elapsed. DBP Awards will vest in full.

Alternatively, the Board may permit Awards to be exchanged for awards of shares in a different company (including the acquiring company). If the change of control is an internal reorganisation of the Group or if the Board so decides, participants may be required to exchange their Awards.

If other corporate events occur such as a winding-up of the Company, demerger, delisting, special dividend or other event which, in the Board's opinion, may materially affect the current or future value of Shares and the Board determines it would not be appropriate or practical to adjust Awards, the Board may determine that Awards will vest (and be released) on the same basis as for a change of control.

Variation of capital

If there is a variation of share capital of the Company or in the event of a demerger, delisting, special dividend or other event which in the Board's opinion may affect the current or future value of Shares, the Board may make such adjustments to the number of Shares subject to Awards and/or any performance condition applicable to Awards as it considers appropriate.

Rights attaching to Shares

Shares issued and/or transferred under the Share Plans will not confer any rights on any participant until the participant in question has received the underlying Shares. Any Shares allotted will rank equally with Shares then in issue (except for rights arising by reference to a record date prior to their issue).

Amendments

The Board may, at any time, amend the provisions of the Share Plans in any respect. The prior approval of Shareholders at a general meeting of the Company must be obtained in the case of any amendment to the advantage of eligible employees or participants which is made to the provisions relating to eligibility, individual or overall limits, the basis for determining the entitlement to, and the terms of, Awards, the adjustments that may be made in the event of any variation to the share capital of the Company and/or the rule relating to such prior approval. There are however exceptions from this requirement to obtain shareholder approval for any minor amendment to benefit the administration of the Share Plans, to take account of the provisions of any legislation or to obtain or maintain favourable tax, exchange control or regulatory treatment for any participant or member of the Group. No amendment may be made to the material disadvantage of the existing rights of participants unless every participant who may be affected by such amendment has been invited to indicate whether or not he approves the amendment, and the amendment is approved by a majority of those who have so indicated.

Non-transferability

Awards are not transferable other than to the participant's personal representatives in the event of his or her death.

Benefits not pensionable

Benefits received under the Share Plans are not pensionable.

Overseas plans

The Board may, at any time, establish further plans based on the Share Plans for overseas territories. Any such plan will be similar to the Share Plans but may be modified to take account of local tax, exchange control or securities laws. Any Shares made available under such further overseas plans must be treated as counting against the limits on individual and overall participation under the Share Plans.

Termination

No Awards may be granted under the Share Plans more than ten years after Admission.

8.5 Admission Award

In recognition of the key role played by the Group's employees in the pre-Admission period and in order to ensure they are appropriately aligned with shareholders post-Admission, the Company proposes to make a conditional share award to a number of employees (other than the Executive Directors) in respect of Admission ("**Admission Awards**"). The Admission Awards will be made under the Company's new LTIP over a number of Shares not exceeding 0.5% of the Company's fully diluted share capital immediately following Admission.

8.6 The Company's employee benefit trust

The Company will establish before Admission an employee benefit trust (the "**EBT**") which will be constituted by a trust deed entered into between the Company and a professional trustee. The Company will have the power to appoint and remove the trustee.

The EBT will be used to benefit employees and former employees of the Company and its subsidiaries and certain of their dependents. The trustee(s) of the EBT will have the power to acquire Shares and any Shares acquired may be used for the purposes of the LTIP, the DBP and other employee share plans established by the Group from time to time, or otherwise for the benefit of the beneficiaries of the EBT.

The Group may fund the EBT by loan or gift to acquire Shares either by market purchase or by subscription. Any awards to subscribe for Shares granted to the EBT or Shares issued to the EBT will be treated as counting against the dilution limits that apply to the Share Plans.

The EBT will not make an acquisition of Shares if that acquisition would mean that it held more than 5% of the Company's ordinary share capital (other than as nominee for a beneficiary), without prior shareholder approval.

9. PENSIONS

In UK, the Group offers a pension scheme for its employees, as required by law, which terms are based on contributions starting at 3% employee, 3% employer up to April 2019 and 4% employer 5% employee onwards. The terms have been based on full employee membership provided but will not alter if there are changes made to the numbers or salaries.

In Greece, the Group offers a mandatory pension plan for its employees as required by law, which has the form of a defined benefit plan. According to this plan, employees are entitled to severance pay on retirement, the amount of which varies according to salary level, tenure of service and years of social insurance. Beneficiaries of this payment are employees who are eligible for full retirement, i.e. under the current pension system in Greece, employees aged between 62 and 67 years.

The Group's policy is to carry out every year an independent actuarial valuation of the liabilities with regard to the abovementioned benefit plan. The last actuarial study was completed in December 2016 and the actuarial liability was calculated as US$2.4 million. The liability recognised had increased to US$2.9 million as of October 2017 in line with the increase in FTEs and gross payroll costs.

Based on historical data, the Group expects benefits of approximately US$70,000 to be paid for 2018. For further details on the Group's retirement benefits obligations, see note 20 to the Consolidated Historical Financial Information in Section B of Part 13 "*Consolidated Historical Financial Information*".

10. UNDERWRITING ARRANGEMENTS

10.1 Underwriting Agreement

On 16 March 2018 the Company, the Directors, the Major Shareholders and the Underwriters entered into the Underwriting Agreement. Pursuant to the terms of the Underwriting Agreement:

10.1.1 the Company has agreed, subject to certain conditions, to allot and issue the New Shares at the Offer Price;

10.1.2 the Underwriters have severally agreed, subject to certain conditions, to procure subscribers for or, failing which, themselves to subscribe for the New Shares pursuant to the Global Offer;

10.1.3 the Company has agreed to pay the Underwriters a commission of 2.25% of the product of the Offer Price and the aggregate number of New Shares issued in the Global Offer (excluding the Shares issued to the Directors and Kerogen);

10.1.4 in addition, the Company may, at its absolute discretion, pay to the Underwriters a commission of up to 1.25% of the product of the Offer Price and the number of New Shares issued in the Global Offer (excluding the Shares issued to the Directors and Kerogen);

10.1.5 the obligations of the Underwriters to procure subscribers for or, failing which, themselves to subscribe for the New Shares pursuant to the Global Offer on the terms of the Underwriting Agreement are subject to certain conditions. These conditions include the absence of any breach of representation or warranty under the Underwriting Agreement and Admission occurring on or before 21 March 2018 (or such later time and/or date as the Joint Global Co-ordinators and the Company may agree in writing). In addition, the Joint Global Co-ordinators have the right to terminate the Underwriting Agreement, exercisable in certain circumstances, prior to Admission. The Underwriting Agreement will become unconditional on Admission;

10.1.6 the Company has agreed to pay the costs, charges, fees and expenses of the Global Offer (together with any related value added tax);

10.1.7 each of the Company and the Directors has given certain customary representations, warranties and undertakings, to the Underwriters. The liability of the Company pursuant to the Underwriting Agreement is unlimited by time and amount. The liability of the Directors is limited by time and amount;

10.1.8 the Company has given an indemnity to the Underwriters on customary terms; and

10.1.9 the parties to the Underwriting Agreement have given certain covenants to each other regarding compliance with laws and regulations affecting the making of the Global Offer in relevant jurisdictions.

11. SUBSIDIARIES, INVESTMENTS AND PRINCIPAL ESTABLISHMENTS

The Company is the principal operating and holding company of the Group. The principal subsidiaries and subsidiary undertakings of the Company are as follows:

11.1 Subsidiaries and subsidiary undertakings

Name	Country of incorporation and registered office	Percentage of ownership interest and voting power	Field of activity
Energean E&P Holdings Limited	Cyprus	100%(1)	Holding Company
Energean Oil & Gas SA	Greece	100%	Greek producing and development assets
Energean International Limited	Cyprus	100%	Intermediate holding company
Energean Montenegro Limited	Cyprus	100%	Montenegrin exploration assets
Energean Israel Limited	Cyprus	50.0001%(2)	Israeli development assets
Energean Israel Finance S.à r.l. (Luxembourg)	Luxembourg	50.0001%(3)	Israel development assets financing
Kavala Oil S.A.	Greece	99.9%	Greek exploration assets

(1) The Company directly holds 99.7% of the issued share capital of Energean E&P Holdings, with the remaining 0.3% of the issued share capital of Energean E&P Holdings held on trust for the Company, pending finalisation of the share transfer on the terms of the Reorganisation Agreement.

(2) The Group currently has a 50% economic interest in Energean Israel, with 50.0001% of the voting rights. On 28 December 2017, Energean E&P Holdings entered into an agreement to acquire a further 20% interest in Energean Israel by means of a subscription of new shares in Energean Israel. It is expected that such subscription will complete in the first quarter of 2018.

(3) Energean Israel Finance S.à r.l. (Luxembourg) is a 100% subsidiary of Energean Israel Limited.

11.2 Principal establishments

The following are the principal establishments, other than its fields, of the Group:

Name and location	Type of facility	Tenure
Head office—21 Gloucester Place, London, United Kingdom, W1U 8HR	Office	Lease, terminates 15 January 2019
Cyprus Office—6th Floor, 36 Vyronos, 1096 Nicosia, Cyprus	Office	Lease—may be terminated on one month's notice
Athens Office—32, Kifisias Avenue, 15125 Marousi, Atrina Center 16o Floor, Athens	Office	Lease—may be terminated on three months' notice
Athens Office—32, Kifisias Avenue, 15125 Marousi, Atrina Center 17o and 18o Floor	Office	Lease—may be terminated on three months' notice
Tel Aviv Office—21st Floor, Kinneret 5 Bnei Brak, Israel	Office	Lease—terminates 28 February 2019

12. MATERIAL CONTRACTS

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by the Company or another member of the Group: (a) within the two years immediately preceding the date of this Prospectus which are, or may be, material to the Company or any member of the Group, and (b) at any time and contain provisions under which the Company or any member of the Group has an obligation or entitlement which is, or may be, material to the Company or any member of the Group as of the date of this Prospectus:

12.1 Underwriting Agreement

The Underwriting Agreement is described in paragraph 10.1 of this Part 16 "*Additional Information*".

12.2 Relationship Agreements

The Relationship Agreements are described in paragraph 2 of Part 9 "*Principal Shareholders and Related Party Transactions—Relationship Agreements*".

12.3 Reorganisation Arrangements

The Reorganisation Agreement and the Supplementary Agreement is described in paragraph 3.1 of Part 9 "*Principal Shareholders and Related Party Transactions—Reorganisation in connection with Admission"*.

12.4 Senior Credit Facility for the Karish-Tanin Development

On 2 March 2018, Energean Israel entered into the Senior Credit Facility (pursuant to which Energean Israel Finance S.à r.l. shall be the immediate borrower with the loan proceeds to be on-lent to Energean Israel), being a US$1.275 billion senior facility agreement (governed by English law with jurisdiction of the English courts) underwritten by a club of Israeli and international banks (with Bank Hapoalim B.M, Morgan Stanley Senior Funding, Inc., Natixis and Société Générale, London Branch, as mandated lead arrangers) for the purposes of, amongst other things, financing the development of the Karish field, paying debt service (other than principal) and paying deferred payments due from Energean Israel to the Delek Sellers pursuant to the terms of the sale and purchase agreement entered into on 16 August 2016 and made between the Delek Sellers and Energean Israel. The tenor of the Senior Credit Facility is 3.75 years with a single bullet payment on the final maturity date. Interest periods are three months with the applicable margin being LIBOR plus the following margin ratchet—(a) Months 1-12: 3.75% per annum; (b) Months 13-24: 4% bps per annum; (c) Months 25-36: 4.25% bps per annum; and (d) Months 37-45: 4.75% bps per annum. Energean Israel shall pay a commitment fee of 30% on the applicable margin on available unused commitments accruing from the signing date and paid quarterly in arrears.

The lenders benefit from a comprehensive security package over the assets of Energean Israel (and Energean Israel Finance S.à r.l.) which includes the following: (a) Energean E&P Holdings and Kerogen (each an "**EISL Shareholder**", and together, the "**EISL Shareholders**") pledge their shares in Energean Israel and assign their rights under shareholder loans; (b) Energean Israel has entered into an Israeli law pledge agreement which creates a fixed charge over all its assets located in Israel including the Karish and Tanin leases and gas sale and purchase agreements; (c) an English law security agreement in respect of Energean Israel's interests in the English law governed project documents and insurances and bank accounts located in London; and (d) an all-asset security agreement governed by Cyprus law creating security over Energean Israel's assets located in Cyprus. In addition, direct agreements have been, or will be, entered into in respect of certain of the project documents, including the EPCIC contract with TechnipFMC and the operations and maintenance agreements with Wood Group UK Limited. There are no EISL Shareholder or sponsor guarantees, debt service undertakings or cost overrun support (save for a capped contingent equity support payment of US$20 million from Energean E&P Holdings and a further up to US$125 million contingent equity support payment from Energean E&P Holdings to cover certain deferred payments under the Technip EPCIC Contract that would only be payable by Energean E&P Holdings if the acceptable credit rated bank issuing a letter of credit covering such amount fails to pay out that amount): construction risk is taken by the banks, relying primarily on obligations pursuant to the Technic EPCIC Contract.

As a condition precedent to funding, Energean Israel is obliged to demonstrate that (a) a debt-to-equity ratio no greater than 66:34 has been satisfied; (b) a projected debt service coverage ratio for each six month period from the test date to the date that is twelve years following the final maturity date is no less

than 1.5:1; (c) Energean Israel has entered into gas sale and purchase agreements for sales of petroleum from the Karish field to enable Energean Israel to satisfy the aforementioned projected debt service coverage ratio; (d) an equity contribution of US$525.8 million in aggregate (US$60.0 million of which having already been contributed as of the date of the Senior Credit Facility); (e) approval of the Karish Lease Environmental Document by the Israeli Petroleum Commissioner; and (f) certain other conditions precedent customary for a financing of this type have been satisfied.

Energean Israel is required to mandatorily prepay the Senior Credit Facility in the following circumstances: (a) following the occurrence of an illegality event on customary terms; (b) following a change of control in Energean Israel, defined as Energean E&P Holdings ceasing to own at least 25%, or the current shareholders of Energean Israel ceasing to own at least 51% of the voting shares in Energean Israel; (c) following a change of control in Energean E&P Holdings; (d) following receipt of insurance proceeds above an agreed threshold (and subject to certain exceptions); and (e) following the first drawdown date of any refinancing of the Senior Credit Facility (a "**Take-out Financing**"). As the Senior Credit Facility is structured to enable a capital markets refinancing, on the last day of each interest period on which cashflows become positive (the "**Positive Cashflow Date**"), 100% of the excess cash available in the proceeds account shall be applied to a refinancing reserve account secured in favour of the lenders. If a Take-out Financing is not in place at the final maturity date, all amounts standing to the credit of the refinancing reserve account shall be applied in discharge of amounts outstanding under the Senior Credit Facility. The Senior Credit Facility contains representations, covenants and events of default substantially consistent with other recent similar financings in the region; no distributions are permitted prior to the final maturity date.

12.5 RBL Senior Facility Agreement

In May 2016, EOGSA, as borrower, signed the EBRD Senior Facility Agreement with EBRD, subsequently amended on 12 July 2016, for a US$75 million borrowing base facility to fund EOGSA's development program in the Prinos, Prinos North and Epsilon fields. On 30 January 2018 the EBRD Senior Facility Agreement was amended and restated to increase the facility amount up to US$ 180 million pursuant to the RBL Senior Facility Agreement. The terms and conditions of the RBL Senior Facility Agreement comprise two facilities:

(a) a facility up to US$ 105 million comprising EBRD and Black Sea Trade and Development Bank ("**BSTDB**") as lenders (the "**IFI Facilities**" that is divided into two tranches, a tranche pursuant to which EBRD is the lender (the "**EBRD Tranche**") and a tranche pursuant to which BSTB is the lender (the "**BSTDB Tranche**")); and

(b) a Romanian club facility of up to US$ 75 million pursuant to which the Export-Import Bank of Romania Eximbank SA ("**Romanian ECA**") and Banca Comerciala Intesa Sanpaolo Romania S.A. (benefitting from 95% insurance cover from the Romanian ECA) will be lenders (the "**Romanian Club Facility**").

Energean E&P Holdings agrees to subordinate its claims against EOGSA and provides a guarantee for all amounts owing by EOGSA under the RBL Senior Facility Agreement, in each case, in favour of the lenders. The lenders will also benefit from security over substantially all the assets of EOGSA – including security over EOGSA's offshore and onshore bank accounts and all balances and claims arising from such accounts, certain material agreements, including the BP Offtake Agreement, the GSP EPCIC Contract and KOSA services agreement, and certain insurance policies which EOGSA is required to maintain, as well as a first priority mortgage over the Energean Force, a pledge by Energean E&P Holdings of its shares in EOGSA, and a pledge by EOGSA of its shares in KOSA. The IFI Facilities and the Romanian Club Facility will share the any proceeds from the enforcement of security pari passu pursuant to the terms of an intercreditor agreement.

The purpose of the facilities is to finance, amongst other things, the development of the Prinos, Prinos North and Epsilon oil fields. The Romanian Club Facility will finance exclusively 85% of the values attributable to eligible goods and services under the service contract entered into between EOGSA and GSP offshore SRL in December 2017.

The RBL Senior Facility Agreement is drafted on the basis of a customary reducing borrowing base facility arrangement whereby the maximum amount that can be drawn or outstanding on any date shall be the lesser of the total commitments (being US$ 180 million) and the borrowing base amount. The borrowing base amount shall be calculated by reference to a banking case derived from an agreed financial model prepared by the technical bank prior to each semi-annual redetermination date. The

borrowing base amount, in relation redetermination period (periods of six months), shall be the amount set out in the banking case which is the maximum amount of the loans that could be outstanding in such calculation period whilst ensuring a field life cover ratio of not less than 1.5:1 and a loan life coverage ratio of not less than 1.3:1 for each calculation period until the applicable final repayment date. The borrowing base amount will be approved by the lenders on each redetermination date.

The IFI Facilities will have a tenor of seven years from May 2016 and the Romanian Club Facility will have a tenor of seven years from 31 October 2017 and matures on 31 October 2024. Each of the facilities are revolving facilities and subject to semi-annual reductions in accordance with an agreed amortisation schedule – each of the total commitments shall reduce over the life of the facilities in accordance with an agreed reduction schedule. EBRD and BSTDB commitments will each reduce to US$45 million on 31 October 2020, US$37.5 million on 30 April 2021, US$30 million on 31 October 2021, US$22.5 million on 30 April 2022, US$15 million on 31 October 2022, US$7.5 million on 30 April 2023 and nil on 31 October 2023. The Romanian Club Facility will term-out after the end of the availability period for the Romanian Club Facility and is repayable in equal six month instalments beginning on 30 April 2020 to 31 October 2024.

EOGSA shall pay commitment fees at the rate of 40% of the margin on not utilised but available amounts and 25% of the margin on unavailable amounts. The interest rate on the IFI Facilities is LIBOR plus a margin of 4.9% per annum and the interest rate on the Romanian Club Facility is LIBOR plus 3% per annum (with the insurance premium to be paid in up to six instalments, being 6.65% flat). Interest periods will be either three or six months.

The RBL Senior Facility Agreement contains prepayment and cancellation provisions customary for a facility of this type such as illegality, voluntary prepayment, mandatory prepayment of disposals except for permitted disposals (meaning disposals below US$ 5 million of assets that are not borrowing base assets that are not borrowing base assets or assets secured in favour of the lenders at the signing date), mandatory prepayments of insurance claim proceeds except for excluded insurance proceeds (meaning proceeds of any partial loss insurance claims in relation to assets that are not borrowing base assets or assets that are not secured in favour of the lenders at the signing date) and a mandatory prepayment for a change of control, which shall not be triggered by an initial public offering of the Shares in the Company.

The RBL Senior Facility Agreement imposes a number of affirmative and negative covenants on the Group. Affirmative covenants include, among other things, compliance with the Prinos development plan, environmental and social action plan and hedging policy, applicable laws and tax rules and with its obligations under its licences; maintenance of certain bank accounts, insurance policies and material agreements; and compliance with certain financial ratios. Such financial ratios include a historic debt service coverage ratio after 31 December 2020 of note less than 1.10:1 (the historic debt service coverage ratio being, at each calculation date, the ratio of cash available for debt service in the preceding twelve months to the sum of principal and interest repayments on all financial indebtedness, other than shareholder loans, due in such period); a field life coverage ratio of not less than 1.30:1 (the field life coverage ratio being, at each calculation date, the ratio of the net present value of projected net revenues for the present and subsequent periods to the aggregate amount of the principal outstanding under the EBRD Senior Facility Agreement); a loan life coverage ratio of not less than 1.20:1 (the loan life coverage ratio being, at each calculation date, the ratio of the net present value of projected net revenues for the present and subsequent periods on or before the final repayment date to the aggregate amount of the principal outstanding under the facilities); and a debt to equity ratio of not more than 70:30.

Subject to terms therein, the RBL Senior Facility Agreement permits equity contributions by Energean E&P Holdings or its affiliates to cure non-compliance with such ratios. EOGSA must also comply with a recurring liquidity test – total corporate uses must not exceed total corporate sources in the next twelve month period. The Group must also furnish financial, compliance and other information to the EBRD and publicly disclose tax and other government payments.

The RBL Senior Facility Agreement also contains negative covenants, including, among other things, a prohibition on distributions, including shareholder loan payments, by EOGSA and Energean E&P Holdings and, with respect to EOGSA, Energean E&P Holdings and KOSA, a negative pledge and restrictions on capital expenditure, investments, leases, additional financial indebtedness, derivatives transactions, profit sharing and management arrangements, transactions not at arm's length, disposals, acquisitions, investments and asset sales, and changes in the entities' business, capital or charter or certain material agreements. The RBL Senior Facility Agreement also contains negative covenants regarding flaring of gas and certain other prohibited activities.

12.6 EBRD Subordinated Facility

In July 2016, EOGSA, as borrower, signed the EBRD Subordinated Facility Agreement, a subordinated loan agreement with the EBRD, subsequently amended on 8 March 2017 and 28 February 2018, for a US$20 million facility to fund EOGSA's exploration activities. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission and an EBITDA participation amount of up to 3.5% of EBITDA (if EBITDA is positive) for the financial years 2016 and 2017 and up to 4.0% of EBITDA (if EBITDA is positive) thereafter, depending on the amount of the facility drawn. For these purposes, EOGSA's EBITDA is defined in the agreement as the total consolidated operating profit of the borrower before taking into account interest expense, taxes and extraordinary and exceptional items, and after adding back all amounts provided for depreciation and amortisation for such period, as shown in the most recent financial statements provided to the EBRD by EOGSA as set out in the agreement. The EBITDA participation amount shall accrue on a yearly basis from 1 January 2016 until 31 December 2024 and shall be payable in full on 25 August 2025. Subject to provisions regarding mandatory and voluntary prepayment, the facility is repayable in four equal instalments on 25 November 2024, 25 February 2025, 25 May 2025 and 25 August 2025. EOGSA shall pay EBRD a restructuring fee of US$0.1 million on the earlier of the first disbursement under the RBL Senior Facility Agreement and 30 days following the effective date as defined therein. The facility is secured by the second ranking pledge and assignment as security of all of EOGSA's offshore and onshore bank accounts and all balances and claims arising from such accounts, certain material agreements, including the BP Offtake Agreement and KOSA services agreement, and certain insurance policies which EOGSA is required to maintain, as well as a mortgage over the Energean Force and second ranking pledges by Energean Holdings of its shares in EOGSA, by EOGSA of its shares in KOSA, and by Energean International of its interest in its intercompany loan to EOGSA dated 14 August 2014 as amended and restated 3 April 2015.

The EBRD Subordinated Facility Agreement imposes a number of affirmative and negative covenants on the Group. Affirmative covenants include, among other things, compliance with the environmental and social action plan set out in the agreement and the projects funded under the EBRD Senior and Subordinated Facility Agreements as well as applicable laws and tax rules and the obligations under its licences; provision to the EBRD of reports on the progress of EBRD-funded projects and the environmental and social action plan in the agreement; maintenance of certain bank accounts and insurance policies; provisions to the EBRD of a copy of agreements in excess of US$2 million relating to the Group's exploration activities and maintenance of and compliance with such agreements; furnishing financial, compliance and other information to the EBRD and public disclosure of tax and other government payments; ensuring prompt payment and compliance by Energean Montenegro under the terms of the intra-group loan from EOGSA to Energean Montenegro (the "**Energean Montenegro Loan**") and provision to the EBRD of information in relation to such loan. EOGSA must also maintain a leverage ratio of not more than 2.5:1.

The EBRD Subordinated Facility Agreement also contains negative covenants, including, among other things, a prohibition on distributions, including shareholder loan payments, by EOGSA and Energean E&P Holdings and, with respect to EOGSA, Energean E&P Holdings and KOSA, a negative pledge, restrictions on capital expenditure, investments, leases, additional financial indebtedness, derivatives transactions, profit sharing and management arrangements, transactions not at arm's length, disposals, acquisitions, investments and asset sales, and changes in the entities' business, capital or charter, material agreements relating to its exploration activities or the Energean Montenegro Loan. The agreement also contains negative covenants regarding flaring of gas and certain other prohibited activities.

12.7 Kerogen Interim Facility Agreement

Energean Israel, as borrower, Energean E&P Holdings, as parent, Kerogen, as lender, and Oilco Investments, Growthy Holdings, Adobelero, Mathios Rigas, Efstathios Topouzoglou and Panos Benos as chargors entered the Kerogen Interim Facility Agreement, an interim facility agreement dated 19 December 2016, for a term loan of up to US$40 million to fund Energean Israel's acquisition of the Karish and Tanin leases and related costs. US$30 million of the proceeds was applied to the closing payment under the transaction to purchase the Karish and Tanin leases and up to US$10 million was applied to pre-final investment decision costs and certain taxes specified in the agreement. Energean Israel fully utilised the Kerogen Interim Facility. In June 2017, pursuant to the EISL Subscription Agreement and the EISL Shareholders Agreement, the facility was converted, together with a further equity investment by Kerogen of US$10 million in Energean Israel, to an approximately 50% equity interest in Energean Israel.

12.8 EISL Subscription Agreements

Energean Israel and Energean E&P Holdings entered into a subscription agreement (the "**EISL Subscription Agreement**") dated 19 December 2016 with Oilco Investments, Growthy Holdings and Adobelero and Kerogen (together with the Founders, the "**EISL Subscribing Shareholders**"). Pursuant to the EISL Subscription Agreement, the existing shares in Energean Israel held by Energean E&P Holdings were re-designated into 422,000 A shares. Additionally, Oilco Investments and Growthy Holdings each acquired 200,449 B2 shares for a consideration of US$4.75 million and Adobelero acquired 21,101 B2 shares for a consideration of US$0.5 million (in each case in repayment of certain existing shareholder loans).

Furthermore, the parties agreed that the Kerogen Interim Facility could be repaid by the issue of certain A shares and B1 shares to Kerogen (including in respect of any further advances under the Kerogen Interim Facility up to a maximum aggregate funding amount of US$50 million). On 13 June 2017, Energean Israel issued 421,998 A shares and 421,999 B1 shares to Kerogen in repayment of all advances made under the Kerogen Interim Facility Agreement.

The EISL Subscription Agreement included customary warranties from the parties, together with various covenants regarding the terms of acquisition of the Karish and Tanin leases.

Pursuant to the Reorganisation Agreement, the B2 shares acquired by the Founders were acquired by the Company on 15 March 2018 in exchange for US$10 million in cash. See *"Principal Shareholders and Related Party Transactions—Related party transactions—Reorganisation in connection with Admission"*.

On 28 December 2017, Energean Israel, Energean E&P Holdings, the Founders and Kerogen entered into the Second EISL Subscription Agreement, based on commercial terms agreed in October 2017, pursuant to which Energean E&P Holdings agreed to subscribe for additional 562,662 A shares and 562,665 B2 shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash (to be funded from the use of proceeds from the Global Offer). This sum includes the amount payable in respect of Energean's carry of 20% of Energean Israel for US$80 million, together with its 70% proportionate share of funding in respect of such carry. Upon completion of such subscription, Energean E&P Holdings will hold 70% of the shares in Energean Israel. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018 (or 30 June 2018 if Kerogen so consents). Energean E&P Holdings may in its sole discretion also subscribe for such shares prior to such final investment decision being taken. Each of Kerogen and Energean E&P Holdings agrees to approve the final investment decision if certain conditions are satisfied, including if Energean Israel has entered into the Senior Credit Facility and the Technip EPCIC Contract and approved the budget for FID.

The Second EISL Subscription Agreement includes customary warranties from the parties, together with various covenants regarding the terms of acquisition of the Karish and Tanin leases.

12.9 EISL Shareholders' Agreement

Energean Israel and Energean E&P Holdings entered into the EISL Shareholders' Agreement with Kerogen and the Founders. The agreement contains provisions on various matters relating to Energean Israel's activities, including its management, accounting, shareholder information rights, legal compliance, and rules regarding meetings of the board of directors and shareholders, and limits Energean Israel's business to the operation of the developing and commercialising the Karish and Tanin leases.

The agreement contains provisions for the appointment and removal of Energean Israel directors, where the board shall comprise between two and six directors. Each shareholder holding at least 10.0% of the Energean Israel A shares (each 10.0% holding a "**Relevant Shareholding**") may appoint one director per Relevant Shareholding up to a maximum of three directors. The board's initial chairman was appointed by Kerogen, with subsequent chairmen to be selected by the Energean Israel board. The initial directors appointed by Energean E&P Holdings were Mathios Rigas, Efstathios Topouzoglou and Panos Benos.

Energean Israel is required to establish and maintain a joint technical and operating committee to consider and provide input to the board on technical and operational matters. Each shareholder may appoint to this committee one member per Relevant Shareholding, up to a maximum of three members. Energean Israel also established a joint corporate development committee to review and consider matters relating to the corporate development of the Israeli assets. Each shareholder may appoint to this committee one member per Relevant Shareholding, up to a maximum of three members.

The chief executive officer and chief financial officer (together "**executive management**" or "**executive managers**") are responsible for day to day management of Energean Israel, subject to certain consent requirements described below. The agreement provides that Mathios Rigas will serve as chief executive officer and Panos Benos as chief financial officer. The board of directors may appoint and remove executive management. In addition, Kerogen, with the consent of a director appointed by Energean E&P Holdings and not an executive manager, may remove an executive manager if such person has materially breached his responsibilities or the development or operation of the Israeli assets has materially deviated from the agreed strategic plan and annual work program and budget.

Consent from Kerogen is required on a number of matters, including, among others, adoption or amendment of any annual work program and budget; material amendment or deviation from a strategic plan; certain capital expenditure; entry into an FID or definitive FDP in respect of the Israeli assets or any future upstream assets; changes to capital structure; the issue or variation of any securities or rights; certain acquisitions, disposals, mergers, joint ventures, and any initial public offering; changes to agreements governing the Israeli assets; material contracts; related party transactions; and distributions.

Other than as described below, the agreement limits share disposals to a member of the transferor's Shareholder Group, parties not restricted from holding shares under the agreement for legal compliance or other reasons, or with Kerogen's consent, provided that Energean E&P Holdings cannot hold less than 25% of the A shares other than with the consent of Kerogen. In the event of a change of control of a member of the Group, Kerogen may within 10 business days direct such shareholder to transfer all of its shares to the Founders; in the event of a change of control of Kerogen, the Energean Group may direct Kerogen to transfer its shares to Kerogen Energy Fund II LP or its affiliates.

Subject to government approvals and other terms in the agreement, so long as it holds at least one Relevant Shareholding, Kerogen may sell all of its Energean Israel shares to Energean E&P Holdings in exchange for a non-operating, participating interest in the Israeli Assets equivalent to the equity proportion of the B shares held by Kerogen and its affiliates. In such event, the parties shall enter into relevant assignment documents and a joint operating agreement.

Subject to government approvals, if a final investment decision is not made by 31 December 2018 due to less than 3.0 BCM per year of gas offtake volumes having been contracted in respect of the Israeli Assets, then Kerogen may, notwithstanding board approval, direct Energean Israel to sell the Karish and Tanin assets and distribute all proceeds to the shareholders in Energean Israel.

The agreement provides for various warranties among the parties regarding, among other matters, corporate status, authority, solvency, and legal compliance, and indemnities regarding Israeli tax liabilities.

In the event that a shareholder violates certain laws, transfers any of its shares to or becomes or becomes controlled by a restricted transferee, suffers an insolvency event, fails to make a compulsory share transfer or, in the case of Kerogen or fails to comply with its funding obligations under the EISL Subscription Agreement (each event a "**termination event**") it shall give notice of such fact to the other parties. So long as a termination event is continuing, directors nominated by such shareholder will not be entitled to attend or vote at an meeting of the board of directors or shareholders; such shareholder's approval will not be required for any matter requiring the approval of the board of directors or shareholders; if such shareholder is Kerogen, its consent will not be required for certain matters. Subject to remedy provisions, following a termination event, the affected shareholder may sell its shares to a third party within a limited timeframe, subject to terms set out in the agreement. If the affected shareholder fails to do so, the other shareholders will have an option to purchase any securities held by the affected shareholder at a specified fraction of the fair value of the shares as set out in the agreement.

The agreement provides for termination upon winding up of Energean Israel, the acquisition of all the shares by one person, agreement of the parties, occurrence of an initial public offering of Energean Israel or, with respect to each party, when it ceases to hold any shares.

Upon closing of the Second EISL Subscription Agreement, the EISL Shareholders' Agreement will be amended and restated between the relevant parties. The principal effect of such amendment and restatement will be to (i) increase the maximum size of the board of Energean Israel to eight, (ii) allow Energean E&P Holdings to appoint an additional director to the board of Energean Israel, (iii) allow Energean E&P Holdings to appoint an additional member to the joint technical and operating committee and (iv) vary and/or delete certain of the reserved matters relating to the operation of Energean Israel which require the consent of Kerogen before they may be implemented by Energean Israel (which will have the effect of allowing Energean Israel to undertake certain actions without requiring Kerogen's

consent, or increase expenditure on certain business activities before requiring Kerogen's consent, in each case as compared to the current restrictions).

12.10 BP Offtake Agreement

The BP Offtake Agreement is described in paragraph 12.1 of Part 5"*Business Overview—Offtake and marketing—BP Offtake Agreement*".

12.11 Gas Supply Agreements

The Gas Supply Agreements are described in paragraph 12.2 of Part 5 "*Business Overview—Offtake and marketing—Gas Supply Agreements*".

12.12 Arrangements with TechnipFMC

Technip FEED Contract

On 19 October 2017, Energean Israel Limited entered into a contract with TechnipFMC setting out the terms upon which TechnipFMC agreed to provide front-end engineering and design and other pre-final investment decision engineering services to Energean Israel in connection with the Karish-Tanin Development, including engineering and design advice with respect to overall engineering management, subsea engineering project management, subsea systems engineering, subsea basis of design, flow assurance, wellheads and completions, subsea controls, umbilicals, offshore pipelines, risers, tie-ins and pipeline structures. The services under this contract commenced in July 2017 and continued, under variation orders, until February 2018.

Pursuant to this contract, TechnipFMC invoices Energean Israel according to a schedule of milestone payments and the currency shall be in both U.S. dollars and GBP. Each party has provided the other indemnities with respect to sickness, injury and death of personnel, damage to physical property and pollution. The contract contains customary force majeure provisions for such a project. Energean Israel has the right to terminate the contract for any reason, subject to a 30-day notice period, and can terminate immediately in certain circumstances, including material breach without cure and the insolvency of TechnipFMC. The contract contains a limit on the liability of TechnipFMC, subject to certain exclusions.

The original contract value is US$3.6 million and GBP £0.5 million. On 26 October 2017, 6 November 2017 and 31 January 2018, Energean Israel and TechnipFMC entered variation orders for a combined US$9.7 million and £0.8 million. The variation orders extended the work scope to be performed pre-FID to include all remaining FEED scope, selected detailed design elements (accelerated from the envisaged EPCIC scope) as well as FPSO model testing and (in 2018) early commencement of project management engineering services and procurement that have then been accelerated from the planned EPCIC scope of services.

Technip EPCIC Contract

On 2 March 2018, Energean Israel entered into a lump-sum turnkey engineering, procurement, construction, installation and commissioning contract with Technip UK Limited, Technip France SA and the Israeli branch of Technip Ships One Limited (together, "**Technip**") in respect of the development of the Karish field (the "**Technip EPCIC Contract**").

The commencement of the Technip EPCIC Contract is subject to certain conditions precedent, including final investment decision by Energean Israel in respect of Karish and Tanin; provision by Technip of a performance and warranty bond and parent company guarantee from TechnipFMC Plc; provision of a direct agreement executed by relevant contractor entities and satisfaction of all conditions precedent to funding under the Senior Credit Facility. The Technip EPCIC Contract gives each of Energean Israel and Technip the right to terminate such contract, if the commencement date does not occur within 180 days after the effective date of the Technip EPCIC Contract. The Technip EPCIC Contract provides for typical EPCIC contractor warranties including undertaking to correct or remedy any works that do not comply with such warranties, subject to an agreed limit of liability.

Technip bears full risk for site conditions and all design risk under the Technip EPCIC Contract, subject to exceptions for certain adjustments relating to geotechnical and geophysical conditions. Technip shall be responsible for transportation of all plant and equipment to the worksite (other than certain equipment

being supplied but not installed by Technip under the EPCIC Contract which will be delivered to Energean Israel at the manufacturing site for such equipment) and securing relevant permits, approvals and licences, except those which Energean Israel is required to obtain under the contract. Technip shall be responsible for marine operations, including, inter alia, providing all required vessels and inspecting shipyards where the FPSO is constructed. Subject to monitoring by Energean Israel, Technip shall develop and implement quality assurance and control programs, carry out tests and inspections and rectify non-conformance at its own cost. The contract specifies a number of agreed milestones in the development of the project and includes an agreed milestone schedule. Completion of the project is scheduled to occur no later than 31 March 2021. Technip undertakes to remedy any defects in the work noticed within 21 months of completion, to be extended up to 33 months for defects in modifications and repairs.

Pursuant to the Technip EPCIC Contract, Energean Israel has agreed to pay Technip approximately US$1.36 billion (multi-currency), with an option to hedge all non-US Dollar amounts in order to give a fixed total US Dollar amount, for delivery of the project, subject to agreed variations and adjustment only for amounts due and payable to or from Technip as specified in the Technip EPCIC Contract. The contract price will include all charges and provisions necessary for total completion of the works and all taxes other than VAT in Israel. The contract price is payable in accordance with defined milestones, subject to satisfaction of Energean Israel. Energean Israel is entitled to set off amounts owed to Technip against amounts due from Technip (including any liquidated damages), and to withhold payment for defective work and disputed amounts in any invoice. Interest is payable in respect of late payments. The Technip EPCIC Contract also contains a profit sharing arrangement above a certain threshhold.

The Technip EPCIC Contract provides for daily liquidated damages for delays of more than 22 days from the target completion date of 31 March 2021, such liquidated damages increasing at certain intervals, plateauing for delay beyond the 91st day following the target completion date. The Technip EPCIC Contract gives Technip the option of paying performance liquidated damages up to a sub-cap, in the event of certain limited shortfalls in performance at completion against warranted performance levels. Technip's total liability for delay liquidated damages will not exceed a sub-cap; and the aggregate of delay and performance liquidated damages shall not exceed an overall cap based on the contract price. Save as provided in the event of termination events set out in the agreement, such liquidated damages will be Energean Israel's sole remedy in respect of delays or performance shortfalls respectively.

Technip shall provide a performance bond equal to 10% of the contract price for up to six months beyond the completion date, reducing thereafter to 5% until no earlier than the end of the defects liability period. The Technip EPCIC Contract contains typical mutual indemnities for a contract of this kind, with Energean Israel indemnifying Technip for liability in respect of loss or damage to any well or geological formation or arising from pollution and related measures. Energean is responsible for the primary project insurance, namely the construction all risk insurance ("**CAR**"), while Technip is responsible for other insurances, including, inter alia, employers' liability insurance.

The total cumulative liability of Technip to Energean Israel under the Technip EPCIC Contract shall not exceed a cap based on the contract price, subject to exceptions. Neither Energean Israel nor Technip will be liable to the other for consequential damages. Energean Israel shall have the right to suspend the work or any part thereof in the event of Technip's default, if necessary for safety or proper project execution or at its convenience, subject to a variation procedure set out in the EPCIC contract where the suspension does not arise out of Technip's fault. Energean shall have the right to terminate for cause or for its convenience. Technip may not assign or subcontract the EPCIC contract without prior written consent of Energean Israel. Technip shall have the right to suspend or terminate for non-payment of undisputed amounts above a threshold amount.

The Technip EPCIC Contract also contains provisions typical for a contract of this kind regarding variation, intellectual property, force majeure, dispute resolution, sanctions, the duty to cooperate and reporting, including regarding monthly reports and documentation of milestone payment claims.

12.13 Karish and Tanin sale and purchase agreement

On 16 August 2016, the Group entered into an agreement to acquire its interests in the Karish and Tanin leases from Delek and Avner. This included a sale and purchase agreement under which Delek and Avner each sold, assigned and transferred their respective 26.4705% participating interests in each of the Karish and Tanin leases to the Group, and caused Noble to sell and transfer its 47.059% participating interests in each of the Karish and Tanin leases, which Delek and Avner were irrevocably and exclusively authorised to sell, assign and transfer to the Group.

The purchase price was US$148.5 million, of which the Group has paid US$40.0 million and the remainder of US$108.5 million is payable in ten annual payments after the earlier of: (i) the date on which a final investment decision in respect of the Karish-Tanin Development is obtained; and (ii) the date on which the aggregate expenditures in connection with the Karish and Tanin leases exceed US$150 million. In addition, an annual interest charge of 4.6% is applied to the outstanding amounts. These amounts are payable regardless of any gas production in place. The NSAI Israeli CPR estimates that a repayment of approximately US$10.9 million will be made in 2018, US$15.3 million in 2019 and US$14.8 million in 2020, increasing to US$77.0 million in 2021.

The sale and purchase agreement also granted to Delek and Avner (which have since merged together into Delek) overriding royalty interests under which the Group is obliged to pay them an aggregate royalty of 7.5%, increasing to 8.25% on the date on which Energean is first required to make payments on account of the Levy pursuant to the Taxation of Profits from the Natural Resources Law, 5771-2011, less the royalties due under the existing royalties to other third parties, in respect of all natural gas and oil-condensate produced pursuant to the Karish and Tanin leases.

The sale and purchase agreement contained customary warranties for a transaction of this nature.

12.14 GSP EPCIC Contract

On 8 December 2017, Energean Oil & Gas SA and GSP Offshore S.R.L. ("**GSP**") entered into an EPCIC and drilling works contract for drilling and construction related to the Epsilon development program, including the Lamda production facilities and three development wells (as amended, the "**GSP EPCIC Contract**"). Such contract was amended on 6 February 2018. GSP will undertake certain construction and drilling work per the schedule specified in the agreement. The contract price is US$88.3 million, excluding VAT. The contract price comprises US$54.1 million for construction and US$34.2 million for drilling. US$8.1 million of the construction price is payable on the commencement date and witin 90 days of the effective date (8 December 2017) as a condition precedent to contract effectiveness. US$1.8 million of the drilling price is to be paid on the commencement date, with US$3.2 million following rig acceptance and acceptance of the major hazards report by the relevant authorities. Remaining amounts are to be paid in staged payments based on invoices against work completion milestones set out in the contract, subject to certification of completion by Energean. Pricing based on assumptions set out in the GSP EPCIC Contract, including regarding transportation and technical factors including the conditions of the platform location and pipeline route. For the full GSP spread rate and drilling work outside of the agreed scope of work, instructed via a variation order, GSP will be compensated at a daily rate ranging from US$0 (re-drill rate) to US$165,000 (operations day rate) as set out in the agreement. The agreement also provides a schedule of handling charges for purchases of materials, equipment or services outside the scope of the work. For construction works or modifications outside the scope of the works, the agreement provides a schedule of unit rates for management and engineering work, fabrication rates and facilities, offshore installation equipment and miscellaneous supplies and services.

The GSP EPCIC Contract provides for liquidated damages of US$110,000 per day up to a cap of 15% of the contract price for delays beyond 90 days past the scheduled completion (falling eighteen months after the commencement date). GSP's liability under the contract is limited to 35% of the contract price, excluding excess from insurance and liability arising from fraud, gross negligence, wilful misconduct, any amounts due under indemnities, compliance with legislation, liquidated damages, taxation and business standards. Other than in respect of liability for liquidated damages, indemnities, abandonment, fraud, gross negligence, wilful breach or wilful misconduct, neither party shall be liable to the other for consequential loss. GSP has warranted for defects in the work for 24 months following the practical completion date. The agreement contains industry standard indemnities. Energean retains responsibility for pollution and blow-outs, while GSP retains responsibility for re-drilling, maintenance and repair, retrieval of equipment and soil. Energean is required to provide CAR insurance and certain other insurances, and to include GSP as additional insured on its CAR and energy exploration and development policies, while GSP is required to maintain employer's liability, third party, and where applicable hull and machinery and other insurances. Energean is required to obtain required environmental, installation and operations permits. The agreement contains provisions regarding health, safety and environment matters.

Energean may terminate the GSP EPCIC Contract for convenience on 14 days' notice, or upon 10 days' notice for cause as described in the agreement. Energean may terminate with immediate effect if GSP fails to achieve required performance standards, fails to meet the scheduled completion date within 90 days or commences bankruptcy or similar proceedings. GSP may terminate with 30 days' notice

following non-payment by Energean of an undisputed invoice for 30 days and subsequent suspension of work for more than 90 days without payment, subject to a contractual mechanism for investigation and settlement of invoices.

12.15 Stena Drilling Contract

On 25 January 2018, Energean Israel signed a contract (the "**Stena Drilling Contract**") with Stena Forth Drilling Limited ("**Stena Drilling**" or the "**contractor**") for the provision of a mobile drilling rig for the Karish main field development, offshore Israel, to begin between 24 January and 31 March 2019. The agreement incorporates the Logic General Conditions of Contract for Mobile Drilling Rigs, which are amended and supplemented by the terms of the contract. Conditions precedent include execution of a direct agreement relating to Energean Israel's financing of the Karish and Tanin development, execution of parent company guarantee by Stena (UK) Limited, and a final investment decision by Energean Israel, each to occur by 1 July 2018. Pursuant to the Stena Drilling Contract Stena Drilling will deploy the Stena Forth drilling rig or, subject to the acceptance (not to be unreasonably withheld) of Energean Israel, one of the Stena DrillMax, Stena Carron or Stena IceMax rigs. Stena Drilling will drill three firm wells (estimated total drilling time of 230 days) and additionally, at Energean Israel's option, up to two near field exploration wells (estimated drilling time of 60 days per well) and three to five development wells in the Eastern Mediterranean (estimated drilling time of 60 days per well). An operating day rate of US$140,000 per day will apply in respect of the three firm wells and an operating day rate of US$150,000 per day will apply in respect of any further wells drilled at Energean Israel's option as set out above. The contract provides for standby, force majeure and other non-operating rates ranging from 75-85% of the operating rate. Mobilisation and demobilisation costs will be for Stena Drilling's account, but Energean Israel shall reimburse up to US$500,000 of documented mobilisation costs and US$65,000 of demobilisation costs. In addition, the contract provides for a mark-up of 1% to 5% on items procured for Energean Israel, personnel rate adjustments and rate for other services. Payment is on 60 days' invoice. Stena Drilling shall pay Energean Israel US$40,000 per day as liquidated damages in the event of re-drilling or suspension of work as result of default by Stena Drilling.

Energean Israel shall have the right to suspend the work upon written notice in the event of default by Stena Drilling, to ensure safety and proper execution of the of the work or for convenience. Energean Israel may terminate in the event of force majeure, contractor's bankruptcy, breakdown of contractor's equipment for more than 30 days, contractor's breach of material obligations not remedied within five business days of receipt of notice of such breach, contractor's failure to delivery drilling rig within seven days of scheduled commencement date, constructive or total loss of the rig or contractor's failure to comply with anti-bribery laws.

Stena Drilling is required to maintain certain minimum insurances as set out in the agreement and to comply with Energean Israel's health, safety and environmental policy as well as the UK Offshore Safety Directive. The contract contains indemnities typical for a contract of this type. Energean Israel shall indemnify Stena Drilling for pollution arising from the reservoir, its property or the discharge of contaminated cuttings, while Stena Drilling shall indemnify Energean Israel for pollution originating from the hull of the rig or contractor property or equipment above the surface.

Contractor's aggregate liability to Energean Israel is capped at US$10 million in the event of termination for late delivery of the rig and US$7.5 million in the event of termination for any other reason, such limits not applying to any liabilities arising out of wilful misconduct or fraud, or in respect of tax, patents, indemnities, insurance consequential loss or liens. The parties shall not be liable for consequential loss (not to include spread costs or Energean's obligations to pay its other contractors in the event of termination for breach by Stena Drilling). Disputes shall be handled by designated representatives of the parties and, failing resolution by such representatives, by management of the parties. The contract is governed by English law.

13. UK TAXATION

The following statements are intended only as a general guide to certain UK tax considerations and do not purport to be a complete analysis of all potential UK tax consequences of acquiring, holding or disposing of Shares. They are based on current or announced UK legislation and what is understood to be the current practice of HMRC as of the date of this Prospectus, both of which may change, possibly with retroactive effect. They apply only to Shareholders who are resident and, in the case of individuals, domiciled for tax purposes in (and only in) the United Kingdom (except insofar as express reference is

made to the treatment of non-UK residents), who hold their Shares as an investment (other than in an individual savings account or self-invested personal pension arrangement) and who are the absolute beneficial owner of both the Shares and any dividends paid on them. The tax position of certain categories of Shareholders who are subject to special rules (such as persons acquiring their Shares in connection with employment, dealers in securities, insurance companies and collective investment schemes) is not considered.

The statements summarise the current position and are intended as a general guide only. Prospective investors who are in any doubt as to their tax position or who may be subject to tax in a jurisdiction other than the United Kingdom are strongly recommended to consult their own professional advisers.

13.1 Taxation of dividends

The Company is not required to withhold tax when paying a dividend. Liability to tax on dividends will depend upon the individual circumstances of a Shareholder.

13.1.1 UK resident individual Shareholders

Different rates of tax apply to different bands of an individual's dividend income, which for these purposes includes UK and non-UK source dividends and certain other distributions in respect of shares.

An individual Shareholder who is resident for tax purposes in the United Kingdom and who receives a dividend from the Company will not be liable to UK tax on the dividend to the extent that (taking account of any other dividend income received by the Shareholder in the same tax year) that dividend falls within the nil rate band (i.e. the band of an individual's dividend income to which the dividend nil rate of 0% applies).

In the tax year 2017/2018, the nil rate band applies to the first £5,000 of an individual's dividend income. However, pursuant to the Finance (No.2) Act 2017, the nil rate band will be reduced from £5,000 to £2,000 from and including the tax year 2018/2019.

To the extent that (taking account of any other dividend income received by the Shareholder in the same tax year) the dividend exceeds the nil rate band, it will be subject to income tax at 7.5% to the extent that it falls below the threshold for higher rate income tax. To the extent that (taking account of other dividend income received in the same tax year) it falls above the threshold for higher rate income tax then the dividend will be taxed at 32.5% to the extent that it is within the higher rate band, or 38.1% to the extent that it is within the additional rate band (each such rate as applicable in tax year 2017/2018). For the purposes of determining which of the taxable bands dividend income falls into, dividend income is treated as the highest part of a Shareholder's income. In addition, dividends within the nil rate band which (in the absence of the nil rate band exemption) would otherwise have fallen within the basic or higher rate bands will use up those bands respectively and so will be taken into account in determining whether the threshold for higher rate or additional rate income tax is exceeded. For these purposes, the same thresholds apply for Scottish taxpayer Shareholders as in respect of other Shareholders resident in the United Kingdom. Scottish taxpayer Shareholders may wish to consult their own professional advisers if they are in any doubt as to their tax position in respect of dividends.

13.1.2 UK resident corporate Shareholders

It is likely that most dividends paid on the Shares to UK resident corporate Shareholders would fall within one or more of the classes of dividend qualifying for exemption from corporation tax. However, it should be noted that the exemptions are not comprehensive and are also subject to anti-avoidance rules. If a dividend paid on the Shares to a UK resident corporate Shareholder does not fall within one of the exempt classes, the Shareholder will be subject to corporation tax on the gross amount of the dividend at a rate of 19%, falling to 17% from 1 April 2020.

13.1.3 Non-UK resident Shareholders

A Shareholder resident outside the United Kingdom may be subject to non-UK taxation on dividend income under local law. A Shareholder who is resident outside the United Kingdom for tax purposes should consult their own tax adviser concerning their tax position on dividends received from the Company.

13.2 Taxation of disposals

13.2.1 UK resident Shareholders

A disposal or deemed disposal of Shares by a Shareholder who is resident in the United Kingdom for tax purposes may, depending upon the Shareholder's circumstances and subject to any available exemption or relief (such as the annual exempt amount for individuals, being £11,300 in the 2017/18 tax year and £11,700 in the 2018/19 tax year), give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of capital gains.

For such individual Shareholders, any chargeable gain on their disposal of Shares will be subject to capital gains tax at 10% to the extent it is below the higher rate threshold and 20% to the extent that it is above the higher rate threshold (in each case when treated as received on top of any income in that tax year). Individual Shareholders will not be able to benefit from any indexation allowance in respect of any disposal of shares. For these purposes, the same thresholds apply for Scottish taxpayer Shareholders as in respect of other Shareholders resident in the United Kingdom. Scottish taxpayer Shareholders may wish to consult their own professional advisers if they are in any doubt as to their tax position in respect of disposals.

For such corporate Shareholders, any chargeable gain will be subject to corporation tax at a rate of 19%, falling to 17% from 1 April 2020.

13.2.2 Non-UK resident Shareholders

Shareholders who are not resident in the United Kingdom will not generally be subject to UK taxation of capital gains on the disposal or deemed disposal of Shares unless they are carrying on a trade, profession or vocation in the United Kingdom through a branch or agency (or, in the case of a corporate Shareholder, a permanent establishment) in connection with which the Shares are used, held or acquired. Non-UK tax resident Shareholders may be subject to non-UK taxation on any gain under local law.

An individual Shareholder who acquires shares whilst resident for tax purposes in the United Kingdom but subsequently becomes temporarily non-resident and who disposes of all or part of his or her Shares during the period for which he/she is temporarily non-resident may, in certain circumstances, be liable to capital gains tax on his or her return to the United Kingdom, subject to any available exemptions or reliefs.

13.3 Stamp duty and Stamp Duty Reserve Tax ("SDRT")

13.3.1 The Global Offer

No UK stamp duty or SDRT will be payable on the issue of the New Shares by the Company.

13.3.2 Subsequent transfers

Stamp duty at the rate of 0.5% (rounded up to the next multiple of £5) of the amount or value of the consideration given is generally payable on an instrument transferring Shares. An exemption from stamp duty is available on an instrument transferring Shares where the amount or value of the consideration is £1,000 or less, and it is certificated on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions for which the aggregate consideration exceeds £1,000. A charge to SDRT will also arise on an unconditional agreement to transfer Shares (at the rate of 0.5% of the amount or value of the consideration payable). However, if within six years of the date of the agreement becoming unconditional an instrument of transfer is executed pursuant to the agreement, and stamp duty is paid on that instrument, any SDRT already paid will be refunded (generally, but not necessarily, with interest), provided that a claim for repayment is made, and any outstanding liability to SDRT will be cancelled. The liability to pay stamp duty or SDRT is generally satisfied by the purchaser or transferee.

13.3.3 Shares transferred through paperless means including CREST

Paperless transfers of Shares, such as those occurring within CREST, are generally liable to SDRT rather than stamp duty, at the rate of 0.5% of the amount or value of the consideration. CREST is obliged to collect SDRT on relevant transactions settled within the system. The charge is generally borne by the purchaser. Under the CREST system, no stamp duty or SDRT will arise on a transfer of Shares into the system unless such a transfer is made for a consideration in money or money's worth, in which case a liability to SDRT (usually at a rate of 0.5%) will arise.

13.3.4 Shares held through clearance systems or depositary receipt arrangements

Special rules apply where Shares are issued or transferred to, or to a nominee or agent for, either a person whose business is or includes issuing depositary receipts within Section 67 or Section 93 of the Finance Act 1986 or a person providing a clearance service within Section 70 or Section 96 of the Finance Act 1986, under which SDRT or stamp duty may be charged at a rate of 1.5% of the amount or value of the consideration given. Following litigation, HMRC has confirmed that they will no longer seek to apply the 1.5% SDRT charge on an issue of shares into a clearance service or depositary receipt arrangement on the basis that the charge is not compatible with EU law. However, this confirmation has not been reflected in a change to the UK rules. HMRC's view is that the 1.5% SDRT or stamp duty charge will continue to apply to transfers of shares into a clearance service or depositary receipt arrangement unless they are an integral part of an issue of share capital. Further EU litigation however indicates that this view is not correct (at least in respect of certain transfers of only the legal title into a clearance service) but HMRC have not yet confirmed whether they will cease to apply the charge in such cases. Accordingly, specific professional advice should be sought before incurring a 1.5% stamp duty or SDRT charge in any circumstances.

At the Autumn Budget 2017, the government announced that HMRC will continue not to apply the 1.5% stamp duty and SDRT charge on the issue of shares (and transfers integral to capital raising) into overseas clearance services and depositary receipt issuers following the UK's exit from the EU ("exit"). It is reasonable to assume that HMRC will continue not to apply such charges in these circumstances in relation also to UK clearance services and depositary receipt issuers although this is yet to be confirmed.

Except in relation to clearance services that have made an election under Section 97A(1) of the Finance Act 1986 (to which special rules apply), no stamp duty or SDRT is payable in respect of transfers within clearance services or depositary receipt systems. There is an exception from the 1.5% charge on the transfer to, or to a nominee or agent for, a clearance service where the clearance service has made and maintained an election under section 97A(1) of the Finance Act 1986, which has been approved by HMRC. In these circumstances, SDRT at the rate of 0.5% of the amount or value of the consideration payable for the transfer will arise on any transfer of shares in the Company into such an account and on subsequent agreements to transfer such shares within such account.

The statements in this paragraph 13.3.4 apply to any holders of Shares irrespective of their residence, summarise the current position and are intended as a general guide only. Special rules apply to agreements made by, amongst others, intermediaries.

14. CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following is a description of certain U.S. federal income tax consequences to U.S. Holders, as defined below, of acquiring, owning and disposing of Shares, but does not purport to be a comprehensive description of all tax considerations that may be relevant to a particular person's decision to acquire Shares. This discussion applies only to a U.S. Holder that acquires Shares pursuant to the Global Offer and holds the Shares as capital assets for U.S. federal income tax purposes. In addition, this discussion does not describe all of the tax consequences that may be relevant in light of a U.S. Holder's particular circumstances, including alternative minimum tax consequences, the Medicare contribution tax on net investment income, estate and gift tax laws and U.S. state or local tax laws, and does not describe differing tax consequences applicable to U.S. Holders subject to special rules, such as:

- financial institutions;
- regulated investment companies;
- real estate investment trusts;
- insurance companies;
- dealers or traders in securities;
- dealers or traders in currencies and commodities;
- persons holding Shares as part of a hedging transaction, straddle, wash sale, conversion transaction or integrated transaction or persons entering into a constructive sale with respect to the Shares;
- persons whose functional currency for U.S. federal income tax purposes is not the U.S. dollar;
- entities classified as partnerships or pass-through entities for U.S. federal income tax purposes;

- tax-exempt entities, including "individual retirement accounts" or "Roth IRAs";
- certain former citizens or long-term residents of the United States;
- persons holding Shares in connection with a branch, agency or permanent establishment within the United Kingdom; or
- persons that own, directly, indirectly or constructively, ten percent (10%) or more of the voting stock of the Company.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds Shares, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the activities of the partnership. Partnerships holding Shares should consult their tax advisers as to the particular U.S. federal income tax consequences to their partners of acquiring, owning and disposing of such Shares.

This discussion is based on the U.S. Internal Revenue Code of 1986, as amended (the "**Code**"), administrative pronouncements, judicial decisions and final, temporary and proposed Treasury regulations, all as of the date hereof, any of which is subject to change, possibly with retroactive effect.

A "U.S. Holder" is a holder who, for U.S. federal income tax purposes, is a beneficial owner of Shares and is:

- a citizen or individual resident of the United States;
- a corporation, or other entity taxable as a corporation, created or organised in or under the laws of the United States, any state therein or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if a court within the United States is able to exercise primary supervision over its administration and one or more United States persons have the authority to control all substantial decisions of the trust (or otherwise if the trust has a valid election in effect under current Treasury regulations to be treated as a United States person).

U.S. Holders should consult their tax advisers concerning the U.S. federal, state, local and non-U.S. tax consequences of acquiring, owning and disposing of the Shares based on their particular circumstances.

14.1 **Taxation of distributions**

Subject to the discussion below under "*—Passive foreign investment company rules*," distributions paid on the Shares will be treated as dividends to the extent paid out of the Company's current or accumulated earnings and profits (as determined under U.S. federal income tax principles). Distributions in excess of the Company's current and accumulated earnings and profits will be treated first as a non-taxable return of capital, thereby reducing a U.S. Holder's adjusted tax basis in the Shares (but not below zero), and thereafter as either long-term or short-term capital gain depending upon whether such U.S. Holder held the Shares for more than one year as of the time such distribution is actually or constructively received. Because the Company does not maintain calculations of its earnings and profits under U.S. federal income tax principles, it is expected that distributions generally will be reported to U.S. Holders as dividends and be taxable at ordinary income tax rates.

The amount of a dividend paid on the Shares will be treated as foreign-source dividend income and will not be eligible for the dividends-received deduction generally available to U.S. corporations under the Code. Subject to certain holding period requirements and applicable limitations, dividends paid by the Company to certain non-corporate U.S. Holders may be eligible for reduced rates of taxation if the dividends are "qualified dividends" for U.S. federal income tax purposes. Such dividends received with respect to the Shares will be qualified dividends if the Company (i) is eligible for the benefits of a comprehensive income tax treaty with the United States that the U.S. Internal Revenue Service ("**IRS**") has approved for the purposes of the qualified dividend rules and (ii) was not, in the year prior to the year in which the dividend was paid, and is not, in the year in which the dividend is paid, a passive foreign investment company ("**PFIC**") for U.S. federal income tax purposes.

The income tax treaty between the United States and the United Kingdom (the "**U.S.-UK Treaty**") has been approved by the IRS for purposes of the qualified dividend rules and the Company expects that it will generally be eligible for the benefits of the U.S.-UK Treaty. In addition, the Company believes that it was not a PFIC for its taxable year ending 31 December 2017 and, although no assurances can be given, does not anticipate becoming a PFIC for its current taxable year or any foreseeable future taxable year. See the discussion below under "*—Passive foreign investment company rules*".

A dividend will be included in a U.S. Holder's income on the date of the U.S. Holder's actual or constructive receipt of the dividend. The amount of any dividend income paid in pounds sterling will be the U.S. dollar amount calculated by reference to the spot rate of exchange in effect on the date the dividend is actually or constructively received by the U.S. Holder, regardless of whether the payment is in fact converted into U.S. dollars. For purposes of calculating the foreign tax credit, dividends paid on the Shares will be treated as income from sources outside the United States and will generally constitute passive category income. If the dividend is converted into U.S. dollars on the date of receipt, a U.S. Holder should not be required to recognise foreign currency gain or loss in respect of the dividend income. A U.S. Holder may have foreign currency gain or loss if the dividend is converted into U.S. dollars after the date of receipt. In general, foreign currency gain or loss will be treated as U.S.-source ordinary income or loss.

14.2 Sale or other disposition of the Shares

Subject to the discussion below under "*—Passive foreign investment company rules*," a U.S. Holder generally will recognise gain or loss for U.S. federal income tax purposes upon the sale, exchange or other taxable disposition of Shares in an amount equal to the difference, if any, between the amount realised on such sale, exchange or other disposition and the U.S. Holder's adjusted tax basis in the Shares as determined in U.S. dollars. Any such capital gain or loss will be long-term if the U.S. Holder's holding period in the Shares exceeds one year. Long-term capital gains of non-corporate taxpayers are generally eligible for reduced rates of taxation. Any gain or loss generally will be treated as U.S. source gain or loss. The deductibility of capital losses is subject to limitations under the Code.

A U.S. Holder's initial tax basis in the Shares will be the U.S. dollar value of the pound sterling-denominated purchase price determined on the date of purchase. If the Shares are treated as traded on an "established securities market," a cash basis U.S. Holder (or, if it elects, an accrual basis U.S. Holder) will determine the U.S. dollar value of the cost of such Shares by translating the amount paid at the spot rate of exchange on the settlement date of the purchase.

A U.S. Holder that receives pounds sterling from a sale or other taxable disposition of Shares generally will realise an amount equal to the U.S. dollar value of such pounds sterling received on the date of sale or other disposition of such Shares. However, if the Shares are treated as being "traded on an established securities market" pursuant to the Code, a cash basis or electing accrual basis U.S. Holder will determine the U.S. dollar value of the amount realised by translating such amount at the spot rate on the settlement date of the disposition. If an accrual basis U.S. Holder makes the election described above, it must be applied consistently from year to year and cannot be revoked without the consent of the IRS. A U.S. Holder will have a tax basis in any pounds sterling received in respect of a disposition of Shares equal to the U.S. dollar value of such pounds sterling on the settlement date. Any gain or loss recognised upon a subsequent disposition of such pounds sterling will be treated as ordinary income or loss to such U.S. Holder and generally will be U.S.-source income or loss. If a U.S. Holder is an accrual basis taxpayer that is not eligible to or does not elect to determine the amount realised using the spot rate on the settlement date, it will recognise foreign currency gain or loss to the extent of any difference between the U.S. dollar amount of the pounds sterling realised on the date of the disposition and the U.S. dollar value of the pounds sterling received at the spot rate on the settlement date.

14.3 Passive foreign investment company rules

In general, a non-U.S. corporation is treated as a passive foreign investment company, or PFIC, for any taxable year if: (1) 75% or more of its gross income consists of passive income; or (2) 50% or more of the average quarterly value of its assets consists of assets that produce, or are held for the production of, passive income. For this purpose, passive income generally includes, among other things, dividends, interest, rents, royalties and gains from the disposition of investment assets, subject to various exceptions. If the Company owns at least 25% (by value) of the stock of another corporation, it will be treated, for purposes of the PFIC tests, as owning its proportionate share of the other corporation's assets and receiving its proportionate share of the other corporation's income.

Based upon the current and anticipated composition of the Company's gross income and gross assets and the nature of the Company's business, the Company does not believe it was a PFIC for the tax year ending 31 December 2017, and giving effect to the proceeds of the Global Offer, the Company does not anticipate becoming a PFIC for its current taxable year or in the foreseeable future. The Company's PFIC status in any tax year will depend on the Company's income, assets, activities and the Company's market

capitalisation in those years. In addition, the Company's status as a PFIC may depend on how quickly it utilises the cash proceeds from the Global Offer. Because the PFIC determination is made on an annual basis, there can be no assurance that the Company will not be considered a PFIC for any taxable year as a result of an increase in the value or amount of the Company's passive assets, an increase in the amount of the Company's passive income, a decrease in the value of the Company's active assets or a decrease in the amount of the Company's active income. In addition, if the Company is classified as a PFIC in any year during which a U.S. Holder is a shareholder, the Company will continue to be treated as a PFIC with respect to that U.S. Holder in all succeeding years during which such U.S. Holder holds Shares, regardless of whether the Company continues to meet the income or asset test described above.

If the Company was a PFIC for any taxable year during which a U.S. Holder held the Shares, gain recognised by a U.S. Holder on a sale or other taxable disposition (including certain pledges) of the Shares would generally be allocated rateably over the U.S. Holder's holding period for the Shares. The amounts allocated to the taxable year of the sale or other taxable disposition and to any year before the Company became a PFIC would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to tax at the highest rate in effect for individuals or corporations for that year, as appropriate, and an interest charge would be imposed. Further, to the extent that any distribution received by a U.S. Holder on its Shares exceeds 125.0% of the average of the annual distributions on the Shares received during the preceding three years or the U.S. Holder's holding period, whichever is shorter, that distribution would be subject to taxation in the same manner as gain, as described immediately above. Certain elections may be available that would result in alternative treatments (such as mark-to market treatment) of the Shares. U.S. Holders are encouraged to consult their own tax advisors to determine whether any of these elections would be available and, if so, what the consequences of the alternative treatments would be in their particular circumstances. If a U.S. Holder owns the Shares during any year in which the Company is treated as a PFIC, such U.S. Holder generally must file IRS Form 8621 with respect to the Company, generally with the U.S. Holder's federal income tax return for that year. If the Company is treated as a PFIC for a given taxable year, then U.S. Holders of the Shares should consult their tax advisors concerning their annual filing requirements.

14.4 **Information reporting and backup withholding**

Payments of dividends and sales proceeds that are made within the United States or through certain U.S.-related financial intermediaries generally are subject to information reporting, and may be subject to backup withholding, unless (1) the U.S. Holder provides proof of an applicable exemption; or (2) in the case of backup withholding, the U.S. Holder provides a correct taxpayer identification number and certifies that it is not subject to backup withholding.

Backup withholding is not an additional tax. The amount of any backup withholding from a payment to a U.S. Holder will be allowed as a credit against the U.S. Holder's U.S. federal income tax liability and may entitle the U.S. Holder to a refund, provided that the required information is timely furnished to the IRS.

14.5 **Transfer reporting**

In certain circumstances, a U.S. Holder that acquires Shares may be required to file Form 926 with the IRS if the price paid for such Shares by such U.S. Holder, when aggregated with all transfers of cash made by such U.S. Holder (or any related person) to the Company within the preceding twelve-month period, exceeds US$100,000 (or its foreign currency equivalent). Failure by a U.S. Holder to timely comply with such reporting requirements may result in substantial penalties. U.S. Holders should consult their tax advisers to determine whether this reporting requirement is applicable to them.

14.6 **Foreign asset reporting**

Certain U.S. Holders who are individuals (or certain specified entities) may be required to report information relating to an interest in the Shares by attaching a complete IRS Form 8938, Statement of Specified Foreign Financial Assets, to their tax return for each year in which they hold Shares, subject to certain exceptions (including an exception for Shares held in accounts maintained by U.S. financial institutions). U.S. Holders should consult their tax advisers regarding the application of these rules in their particular circumstances.

The above summary is not intended to constitute a complete analysis of all U.S. federal income tax consequences relating to the acquisition, holding and disposition of the Shares. Prospective purchasers of Shares should consult their own tax advisers concerning the tax consequences based on their particular situations.

15. LITIGATION

Save as disclosed in paragraphs 15.1 to 15.7 below, there are no governmental, legal or arbitration proceedings (including such proceedings which are pending or threatened of which the Company is aware) during the 12 months preceding the date of this Prospectus, which may have, or have had, a significant effect on the Company's and/or the Group's financial position or profitability.

15.1 Kavala Oil Workers' Association v. Kavala Oil S.A.

KOSA, the Greek subsidiary of EOGSA, is defendant in a declaratory action filed by the KWA, contesting the validity of the general meeting decision of 8 December 2014 ("**action GMD 2014**"), by which it was resolved to convert the preference shares (without voting rights) which EOGSA had acquired from Regal Petroleum to common shares with voting rights, resulting in EOGSA holding 99.92% of the outstanding common shares and thus diluting KWA's holding from 33% to 0.08%.

KWA alleged a breach of the provisions of the Prinos lease agreement, ratified by Greek Law No 2779/1999, based on the grounds that its shareholding was arbitrarily diluted from the initial holding of 33% of the common shares to 0.08%, in violation to its establishment as the minority shareholder of KOSA. Based on the same grounds, KWA filed a second declaratory action contesting the annual general meeting held on 30 June 2015 ("**action AGM 2015**"), by which the latest share capital increase of €12 million was resolved. Finally, on 20 October 2016 KWA filed a third declaratory action, contesting the validity of the annual general meeting held on 30 June 2016 ("**action AGM 2016**"). The adjourned hearings of the abovementioned actions (action GMD 2014, action AGM 2015 and action AGM 2016) took place on 5 October 2016 and on 16 March 2017, respectively. On 4 April 2017, by decision no. 26/2017, the First Instance Court rejected both action GMD 2014 and action AGM 2015. On 12 February 2018, by decision no. 1/2018 the First Instance Court rejected action AGM 2016 as well. In summary, the court rejected all allegations of the KWA including the allegation that its shareholding was arbitrarily diluted from the initial holding of 33% of the common shares to 0.08%, in violation of the provisions of the Prinos lease agreement, ratified by Greek Law No 2779/1999. The verdict also held that the KWA no longer has the required statutory shareholding interest (higher than 2%) to offend the validity of the general assembly decisions and furthermore, majority shareholder's 'arbitrary' increase of its stake (from 67% up to 98.82%) was not necessary to achieve a quorum and a majority, and consequently, all decisions made during the annual general meeting held on 30 June 2016 are legitimate. In July 2017, KWA appealed decision no. 26/2017, and the first hearing before the Court of Appeal is scheduled for 9 March 2018, and a final and irrevocable decision is not expected to be issued before the summer of 2018. The Group's position is that all the aforementioned cases are without merit and all actions will be rejected by the courts because they lack legal grounds. It is not possible to quantify the impact of granting the declaratory relief requested.

15.2 Kavala Oil S.A. v. OAED

In December 2015, KOSA filed a petition against OAED, the public body for employment and social inclusion in Greece, and the Greek state itself, seeking the payment of €2.5 million (plus interest). This claim is based on the provisions of Art. 21 of the Law Act No 1767/1988 and the Ministerial Decree No 31370/1988, by which KOSA believes it was entitled to receive the abovementioned sum as financial support under the action plan (co-funding by national and EU instruments) for promoting sustainable employment in underdeveloped or deprived districts of Greece, such as the area of Kavala.

Following several postponements of the hearing initiated by the Greek state, the hearing took place on 14 June 2017. The Group is of the view, based on legal advice, that this petition will prevail.

15.3 Kavala Oil S.A. tax appeal

During the year ended 31 December 2014, the statutory tax audit of KOSA for the years 2006 to 2011 was finalised and the official tax report was issued by the respective tax authorities resulting in a €7.3 million fine. This was subsequently reduced after KOSA paid €0.9 million of stamp duties and the tax authorities wrote off €0.9 million in interest and penalties. In addition, under the income tax corrective assessments derived from the tax report, carried-forward tax losses of KOSA were reduced from €28.9 million to €1.4 million. On 22 April 2015, KOSA proceeded in executing its mandatory administrative appeal regarding the remaining balance of €5.6 million before the Dispute Resolution Directorate of the Greek Ministry of Finance. The appeal primarily relates to a transfer pricing-related

fine of €5.3 million relating to transactions between KOSA and EOGSA during fiscal years 2009, 2010, and 2011 which the tax authorities believe were not at arm's length and were provided at a discount. As a result, the authorities intend to impose a penalty calculated as 20% of the amounts (€15.6 million and €11.1 million of gross revenue, for 2010 and 2011 respectively) which they contend represent the gross income forgone by KOSA as a result of these discounts and which KOSA should have recognised as an intra-Group service fee.

A prerequisite for the exercise of the mandatory administrative appeal was the prepayment of 50% of the value of the amounts for which the appeal was executed and thus a total amount of €2.8 million was paid by KOSA during 2015. This amount was presented as advanced payment to Greek tax authorities.

The above mandatory administrative appeals were rejected implicitly by the Dispute Resolution Directorate of the Greek Ministry of Finance. KOSA filed appeals before the Athens Administrative Court of Appeal against all of the decisions of the Dispute Resolution Directorate on 8 October 2015. The discussion of these actions took place in February 2017 and the final decision is expected in the first quarter of 2018. While the Group's management expects to prevail in its mandatory administrative appeal, this cannot be assured. In the event that the decision of the Athens Administrative Court of Appeal is not in favour of KOSA, the remaining amount due of €2.8 million is payable within one month of the decision date and has already been recognised as a provision in the Consolidated Historical Financial Information. In that event and irrespective of the fact that KOSA may submit a further appeal, the penalty will be fully paid and any liability towards the tax authorities will be fully discharged.

In 2017, and in connection with the tax dispute, certain directors of KOSA (namely, Mr Evangelos Pappas, in his capacity as chairman and legal representative of KOSA during the audited financial years 2006 through 2011; Mr Emmanouil Kelaidakis, in his capacity as vice-chairman and legal representative of KOSA during the audited financial years 2006 through 2011; the Group CEO Mr Mathios Rigas, in his capacity as chairman and legal representative of KOSA as of 23 August 2015, the date on which the assessed fines were originally due to be paid; and Mr Dimitrios Gontikas, in his capacity as vice-chairman/CEO and legal representative of KOSA as of 23 August 2015) were indicted *ex officio* and by operation of law (without any need for fault to have been shown by the prosecuting authorities) and charged with failing to have paid the tax in respect of the tax authorities' findings discussed above, which constitutes a criminal offence for the directors under Greek tax law. The trial, scheduled for 4 April 2017, has been postponed to 25 April 2018. The outcome of this prosecution depends on and is associated with the outcome of KOSA's appeal described above, as the criminal offence is eliminated and punishment is not permitted if the amount assessed is fully paid prior to the trial hearing. As a result, the hearing of this criminal case against the KOSA board members will be requested to be postponed up and until the issuance of the pending decision in the appeal. Whether the decision in the appeal is in favour of KOSA or not, the KOSA board members intend to oppose the charge and in any event prosecution against the KOSA directors would cease if the remaining €2.8 million due (plus any accrued interest) is paid prior to any conviction.

15.4 Kavala Oil S.A. pipeline

In 2016, Mr Evangelos Pappas (in his capacity as chairman and legal representative of KOSA during the period from July 2011 to 25 April 2013), Mr Emmanouil Kelaidakis (in his capacity as vice-chairman and legal representative of KOSA during the period from July 2011 to 25 April 2013), the Group CEO Mr Mathios Rigas (in his capacity as chairman and legal representative of KOSA during the period from 26 April 26 2013 onwards) and Mr Dimitrios Gontikas (in his capacity as vice-chairman/CEO and legal representative of KOSA during the period from 26 April 2013 onwards) were indicted under charges of:

(a) environmental degradation, which allegedly consisted of an intentional failure to perform the appropriate actions in order to preserve and prevent the uncovering of a small section of the gas supplying pipeline connecting to the Group's onshore facilities, due to coastal erosion; and

(b) intentionally causing common damage to property by reason of the pipeline's exposed sections suffering increased stress, from their being rocked by the waves, and further being exposed to sunlight corrosion and thus potentially being a source of potential accident with potential effects on human health in case of a breach of the pipeline (although no actual breach of the pipeline had occurred at any time).

By No. 50 First Instance Court Decision issued on 19 January 2017, all five KOSA board members were acquitted with respect to the first charge while the court found negligent liability with respect to the second. Each director was sentenced to a ten-month custodial penalty. No compliance issues with respect to environmental regulations were raised in the Court Decision.

An appeal has been filed, and although the first hearing was scheduled for 8 January 2018, it was postponed to 4 June 2018. The Group is of the view that it is probable that the Court of Appeal, after re-assessing all the evidence, will acquit the directors. However, in the event that the Court of Appeal upholds the conviction, the custodial sentence will be suspended due to its short term of under one year, in accordance with Greek criminal process rules. Such suspensions are generally for a term of three years under Greek law. If, during the period of suspension, the convicted individuals receive any further convictions with sentences of six months or longer, the original conviction revives. In the event that a custodial sentence is not, or is no longer, eligible for suspension, it is generally converted into a pecuniary penalty ranging from €4.50 to €20.00 for each day of the term of the original custodial sentence (or, in this case, approximately €1,350 to €6,000) which would be payable by the directors. Otherwise, once the period of suspension has elapsed, the sentence is fully commuted and no pecuniary penalty is payable. In any event, no direct civil liability or financial costs are expected to arise against KOSA or the Group from this matter.

The Directors believe that indictments against directors in their capacity as legal representatives of a company are relatively common in Greece as under Greek law corporations cannot bear criminal responsibility. Moreover, the Directors believe that Greek prosecuting authorities often indict persons for more serious offences than initial investigation and evidence may appear to warrant.

15.5 Kavala Oil S.A. hazardous waste disposal

On 5 May 2017, Mr Dimitrios Gontikas (in his capacity as vice chairman/CEO of KOSA) was indicted, as legal representative of KOSA, of intentionally committing the alleged offence of improperly disposing of hazardous waste by having placed hazardous waste related to well cuttings, from KOSA's drilling operations, within four open-cast metal pots in an outdoor raw materials storage area at KOSA's premises. According to the indictment, the materials were considered as chemical waste subject to rules regarding its unrestricted disposal. If the court fully agrees with the case of the prosecution, this offence threatens a custodial sentence of between one and five years and/or a fine of up to €60,000. If the court finds no intention but does find negligence on the part of Mr Gontikas or otherwise finds that the extent of any contamination was not material, a custodial sentence is threatened of up to one year and/or a fine. The hearing, initially scheduled for 24 July 2017, has been further postponed to 26 November 2018.

The Directors believe that KOSA took the appropriate measures in storing the well cuttings on its premises and that the indictment has material discrepancies with the text of an on-site inspection report by the Greek Atomic Energy Commission, which states the relevant material found is suitable for further processing without special restrictions. Further the Directors believe that, in any event, the intentional element of committing the offence will be difficult to substantiate and hence that the case is likely be found in the director's favour. In the event of a finding of liability on the part of the director, whether for intent or for negligence, it is likely that any custodial sentence would be eligible for suspension as described above in paragraph 15.4 or otherwise commuted to a pecuniary penalty calculated as described above in paragraph 15.4 and payable by the director. No direct civil liability or financial costs will arise against KOSA or the Group from the director being sentenced to any custodial penalty. Nonetheless, if the court, in addition to or in the absence of, any custodial sentence does award a fine of up to €60,000 as penalty for the offence, KOSA would be jointly liable with the director for its payment.

15.6 Petitions regarding the approval of the FDP for the Karish-Tanin Development

First Petition

On 14 September 2017 the Society for the Protection of Nature in Israel and the Society of Man, Nature and Law, two of the leading local environmental groups in Israel (the "**First Petitioners**"), filed a petition (the "**First Petition**") in the Israeli Supreme Court (having original jurisdiction sitting as the High Court of Justice) against the Ministry of Energy, the Ministry of Environmental Protection, the Planning Administration in the Ministry of Finance and Energean Israel, seeking the revocation of the approval by the Israeli Petroleum Commissioner of the FDP in respect of the Karish-Tanin Development, in order to follow the First Petitioners' preferred procedure, under which certain elements of the Planning and Building Law, 5725-1965 (the "**Israeli Planning and Building Law**") would be applied to the approval process of the FDP. To date, the Israeli government approach has been not to apply the Planning and Building Law outside Israel's territorial waters, in its exclusive economic zone where both the Karish and Tanin Leases are located. This approach is maintained in the Marine Bill, which seeks to create certainty by specifying an exhaustive list of local laws that apply in the EEZ. The Marine Bill has recently passed the first out of three votes in the Israeli Parliament and is currently being prepared for the second and third parliamentary votes.

The approval procedure proposed by the First Petitioners would involve the Group preparing and publishing an environmental impact survey in accordance with the Israeli Planning and Building Law (in addition to the environmental requirements under the Petroleum Law and the applicable terms of the Leases for Karish and Tanin) and a subsequent public review period, a hearing and an approval of a National Planning Institution, prior to approval by the Petroleum Commissioner of the FDP in respect of the Karish-Tanin Development.

Energean Israel submitted its response on 14 January 2018 and the State Attorney submitted its response on 12 February 2018. The Supreme Court has set the hearing for the First Petition for 16 April 2018. The purpose of such hearing would be to determine whether a writ of certiorari should be granted in order to allow a hearing on the merits of the First Petition. If the Supreme Court grants the writ of certiorari, then a hearing on the merits of the First Petition would normally be scheduled a few months after the grant of certiorari and then a decision would normally follow several months thereafter.

Second Petition

On 30 January 2018, Hof Hacarmel Regional Council (the "**Second Petitioner**" and, together with the First Petitioners, the "**Petitioners**"), a regional council adjacent to the Dor onshore facility, filed a petition (the "**Second Petition**") with the Israeli Supreme Court sitting as High Court of Justice, against the Ministry of Energy, the Petroleum Commissioner, two Planning and Construction authorities, Energean Israel and an environmental union of local authorities for Sharon-Carmel, seeking annulment of the decision not to submit the development plan to the National Council for Planning and Construction (the "**National Council**") for approval and to annul the decision to allow Energean to construct "gas pipelines" planned to pass through the maritime "northern zone" of the National Outline Building and Zoning Plan 37/H (the "**NOP**").

The Second Petitioner's claims challenge the State's interpretation of certain provisions of the NOP. According to the State's interpretation, the National Council's approval is only required for development plans which contain treatment facilities in Israeli territorial waters or onshore, where the subject for approval is the allocation of the treatment facilities between onshore and offshore. Since the FDP in respect of the Karish-Tanin Development contains no treatment facilities in Israel's territorial waters and onshore, the approval of the National Council was deemed by the State authorities unnecessary. The Second Petitioner interprets the authority of the National Council differently, and claims that its approval is required for all components of the FDP and not only treatment facilities. The Second Petitioner further claims that according to the NOP the maximum quota for treatment facilities in the maritime northern zone, has already been exploited by the Leviathan FDP.

The Second Petitioner also asked for an interim injunction to suspend any planning procedure and implementation by the respondents, regarding Karish and Tanin until the petition is decided. On February 15, 2018, after all respondents filed their responses to the motion for interim injunction, the Supreme Court declined to grant such an injunction at this point. The Supreme Court has set the preliminary hearing for the Second Petition for 2 May 2018.

Possible outcomes of the Petitions

If, following any hearing on the merits of the Petitions, the Supreme Court were to rule in favour of the Petitioners, the court has considerable discretion with respect to the remedies it may grant. It is difficult at this early stage to assess the likelihood and extent of any remedies that may be granted or imposed, the length of any delay that may be caused by the imposition of any such remedies (or as a consequence of the uncertainty that would accompany the continuation of litigation on these matters), the amount of any increased costs to the Group of implementing any such remedies or any other impacts on the Group's business.

If the Supreme Court chooses to grant the Petitioners the legal remedies they have requested, the approval of the FDP in respect of the Karish-Tanin Development could be revoked. In the case of the First Petition, the Group would need to follow the procedure described above for the re-approval of the FDP before it could proceed with any further development. However, the Supreme Court may also take other routes. In the case of the Second Petition, the Israeli Petroleum Commissioner would need to seek approval of the National Council, which, if modifications to the FDP were required, would require re-approving the FDP. Either such outcome could involve significant delay and increased costs, arising from any conditions which could be imposed by any such re-approval (to the extent that such conditions have not already been met) upon the development of the Karish and Tanin fields, and there can be no assurance such

re-approval would be forthcoming on a timely basis or at all. Any significant delays beyond the long-stop dates determined in the Gas Supply Agreements could ultimately lead to termination of the Gas Supply Agreements.

Although the Directors believe, after due and careful enquiry, that it is unlikely that the outcome of either of the Petitions would have a material impact on the currently anticipated schedule and/or costs of the Karish-Tanin Development, there can be no assurance that the occurrence of any of the foregoing would not have a material adverse effect on the Group's ability to develop or commercialise the Karish-Tanin fields or more generally on the Group's business, results of operations, financial condition and/or prospects.

15.7 Alleged exploration of hydrocarbons without permission

On 2 July 2015, Hellenic Petroleum filed an official letter of complaint against EOGSA dated 26 June 2015 to, among other public agencies, the Kavala Prosecutor's Office in respect of the Group's alleged exploration or exploitation of hydrocarbons without authorisation, in violation of article 12A, paragraph 7 of the Hydrocarbons Law. In particular, the complaint relates to a seismic acquisition campaign conducted by the Group during the period 16 June 2015 – 14 July 2015 for which Hellenic Petroleum alleges the Group did not obtain the requisite consents to undertake the campaign, since the campaign covered a portion of the licence area held by a joint venture between Hellenic Petroleum and its partner Calfrac.

Following the preliminary examination carried out by the Magistrate of Kavala and the Magistrate of Athens, acting following respective orders received by the Chief Prosecutor of Kavala in order to ascertain whether such an offence had been committed, a file was formed consisting of: the Hellenic Petroleum letter of complaint noted above and four affidavits, of which one was given by the Hellenic Petroleum authorised representative and three were given by public officials of the Ministry of Energy in charge at the time, namely the General Director of Energy in the Ministry of Environment and Energy, the Chief of the Hydrocarbon Directorate in the Ministry of the Environment and Energy, the Deputy manager of the Natural Gas Department and Hydrocarbons of the General Directorate for Energy of the Ministry of the Environment and Energy.

In its supplementary note dated 30 October 2015 submitted to the Magistrate of Athens on 2 November 2015, Hellenic Petroleum further alleged that EOGSA did not comply with the interim order of the judge of the Athens Court of First Instance, as it was in force until the issuance of the no. 7642/2015 and also requested the prosecution of the EOGSA's officers for the same act under section 232A of the Greek Penal Code, for non-compliance with an enforceable decision.

Following completion of the preliminary examination, the case was returned to the Prosecutor of Kavala in order to decide a) whether to file the case, b) whether to prosecute and for which offences, c) whether to request additional acts.

Pursuant to the indictment served to the Group's CEO, Mr Mathios Rigas, in his capacity as chairman and CEO of EOGSA at the time of the seismic acquisition campaign, a prosecution has been initiated for intentionally committing: (a) the alleged offence of exercising of the rights of prospecting, exploration and exploitation of hydrocarbons without a licence or such right being granted in accordance with the provisions of the law, punishable by imprisonment for a minimum of two months and by the payment of a pecuniary penalty ranging from €100,000 up to €1.5 million; and (b) the alleged offence of infringement of a provisional order dated 2 July 2015 under which the continuation of the Energean's surveys in the survey area of the joint venture between Hellenic Petroleum and Calfrac had been temporarily suspended.

Pursuant to the indictment served, the date for the first hearing has now been set for 23 May 2018. Given the preliminary stage, it is extremely difficult at this early stage to assess the likelihood of the finding of liability on the part of Mr Rigas, whether for intent or for negligence. In the event of a finding of liability on the part of Mr Rigas, whether for intent or for negligence, it is likely that any custodial sentence would be commuted to a pecuniary penalty calculated as described above in paragraph 15.4 and payable by Mr Rigas in his personal capacity.

16. WORKING CAPITAL

In the opinion of the Company, taking into account the net proceeds receivable by the Company from the Global Offer and the bank and other facilities available to the Group, the Group has sufficient working capital for its present requirements, that is for at least the next 12 months following the date of this Prospectus.

17. SIGNIFICANT CHANGE

Certain significant changes to the Group's financial position and results of operations have occurred since 31 October 2017.

Between May 2017 and February 2018, the Group signed 12 Gas Supply Agreements relating to Karish and Tanin to supply gas in an estimated aggregate amount, following initial commissioning and transition periods, of an average of approximately 4.2 BCM per annum on an ACQ basis (or 3.1 BCM per annum on a take or pay basis), excluding the Or Gas Supply Agreement (up to approximately 4.4 to 5.1 BCM per annum on an ACQ basis or approximately 3.3 to 3.8 BCM per annum on a take or pay basis including the Or Gas Supply Agreement), assuming, inter alia, 95% uptime and reasonable maintenance.

On 26 October 2017, 6 November 2017 and 31 January 2018, Energean Israel and TechnipFMC entered variation orders for a combined US$9.7 million and £0.8 million. The variation orders extended the work scope to be performed pre-FID to include all remaining FEED scope, selected detailed design elements (accelerated from the envisaged EPCIC scope) as well as FPSO model testing and (in 2018) early commencement of project management engineering services and procurement that have then been removed from the planned EPCIC scope of services.

In December 2017, the Group signed an US$88.3 million EPCIC contract with GSP Offshore S.R.L. for drilling and construction related to the Epsilon development program, including the Lamda production facilities and three development wells.

In 2017, Energean Israel participated in Israel's First Offshore Bid Round. Energean submitted bids for block 12 (which sits between the Karish and Tanin leases) and four additional adjacent blocks, including blocks 21, 22, 23, and 31. The bid round was officially closed on 15 November 2017 and awards were announced on 12 December 2017, with Energean receiving all five of the additional licences for which it had bid.

On 28 December 2017, Energean Israel, Energean E&P Holdings, the Founders and Kerogen entered into the Second EISL Subscription Agreement, based on commercial terms agreed in October 2017, pursuant to which Energean E&P Holdings agreed to subscribe for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash. This sum includes the amount payable in respect of Energean's carry of 20% of Energean Israel for US$80 million, together with its 70% proportionate share of funding in respect of such carry. Upon completion of such subscription, Energean E&P Holdings would hold 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%. Energean E&P Holdings has undertaken to subscribe for such shares upon Energean Israel taking a final investment decision in respect of the Karish and Tanin assets on or before 31 March 2018 (or 30 June 2018 if Kerogen so consents).

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities—a facility of up to US$105 million with EBRD and the Black Sea Trade and Development Bank ("BSTDB") as lenders (the "IFI Facility") and a US$75 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA ("Romanian ECA") and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders (the "Romanian Club Facility"). Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP EPCIC Contract. The facility is secured by substantially all of the assets of EOGSA and a guarantee from Energean E&P Holdings and a pledge of its shares in EOGSA. The facility will have a seven-year tenor. For further information on the RBL Senior Facility Agreement, including its covenants and other terms, see "Additional Information—Material Contracts—Senior Borrowing Base Facility".

On 2 March 2018, Energean Israel entered the US$1.275 billion Senior Credit Facility underwritten by a club of Israeli and international banks for the purposes of, amongst other things, financing the development of the Karish field, paying debt service (other than principal) and paying deferred payments due from Energean Israel to Delek and Avner (the "Delek Sellers") pursuant to the terms of the sale and purchase agreement entered into on 16 August 2016 and made between the Delek Sellers and Energean Israel.

On 2 March 2018, Energean Israel, Technip UK Limited, Technip France SA and Technip Ships One Limited agreed an approximately US$1.36 (multi-currency) billion lump-sum turnkey engineering, procurement, construction, installation and commissioning contract relating to the development of the Karish field.

Other than the above, there has been no significant change in the financial or trading position of the Group since 31 October 2017, being the date to which the Consolidated Historical Financial Information in Section B of Part 13 "*Consolidated Historical Financial Information*" relating to the Group was prepared.

18. CONSENTS

18.1 Deloitte LLP is is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has given and has not withdrawn its written consent to the inclusion of the report in Section A of Part 13 "*Consolidated Historical Financial Information*" and Section B of Part 14 "*Unaudited Pro Forma Financial Information*" in the form and context in which they appear, and has authorised the contents of its reports for the purposes of Rule 5.5.3R(2)(f) of the Prospectus Rules. A written consent under the Prospectus Rules is different from a consent filed with the U.S. Securities and Exchange Commission under Section 7 of the U.S. Securities Act. Deloitte LLP has not filed and will not be required to file a consent under Section 7 of the U.S. Securities Act.

18.2 Netherland, Sewell & Associates, Inc., whose registered office is at 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, United States of America, are independent petroleum engineers, geologists, geophysicists and petrophysicists and (in its capacity as a competent person), Netherland, Sewell & Associates, Inc. has given and not withdrawn its written consent to the inclusion in this Prospectus of its reports which are set out in Sections A, B, C and D of Part 19 "*Competent Persons' Reports*" and references to them in the form and context in which they appear and has authorised the contents of those parts of this Prospectus which comprise its reports for the purposes of Rule 5.5.3R(2)(f) of the Prospectus Rules. The Company confirms that, between the date of publication of the NSAI CPRs and the date of this Prospectus, no material changes have occurred, the omission of which would make the NSAI CPRs misleading.

19. GENERAL

The fees and expenses to be borne by the Company in connection with Admission including the FCA's fees, professional fees and expenses and the costs of printing and distribution of documents are estimated to amount to approximately US$13 million (including VAT).

20. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents will be available for inspection during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) for a period of 12 months following the date of this Prospectus at the offices of the Company at 21 Gloucester Place, London W1U 8HR, United Kingdom:

(a) the Articles;

(b) the Consolidated Historical Financial Information, together with the related accountant's report from Deloitte LLP, which is set out in Part 13 "*Consolidated Historical Financial Information*";

(c) the report from Deloitte LLP on the unaudited pro forma financial information, which is set out in Part 14 "*Unaudited Pro Forma Financial Information*";

(d) the Competent Person's Report by Netherland, Sewell & Associates, Inc. set out in Section A of Part 19 "*Competent Persons' Reports*";

(e) the Competent Person's Report by Netherland, Sewell & Associates, Inc. set out in Section B of Part 19 "*Competent Persons' Reports*";

(f) the Competent Person's Report by Netherland, Sewell & Associates, Inc. set out in Section C of Part 19 "*Competent Persons' Reports*";

(g) the Competent Person's Report by Netherland, Sewell & Associates, Inc. set out in Section D of Part 19 "*Competent Persons' Reports*";

(h) the consent letters referred to in "*Consents*" in paragraph 18 above; and

(i) this Prospectus.

PART 17
DEFINITIONS

The following definitions apply throughout this Prospectus unless the context requires otherwise:

"**Act**"	the Companies Act 2006
"**ACQ**"	Annual Contract Quantity
"**Acquisition Shares**"	the new Shares to be issued to Third Point on the terms of the Reorganisation Agreement and the Supplementary Agreement in consideration for the acquisition of the EIL Preference Shares
"**Admission**"	the admission of the Shares to the premium listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities
"**Admission Awards**"	conditional share awards issued to a number of key employees (other than the Executive Directors) in respect of the Admission as more particularly described in Paragraph 8.5 of Part 15 "*Additional Information"*
"**Adobelero**"	Adobelero Holdings Co. Limited (beneficially owned and controlled by Panos Benos)
"**Alon Tavor**"	I.P.P. Alon Tavor Ltd.
"**Articles**"	the articles of association of the Company to be adopted upon Admission
"**Ashdod Energy**"	Ashdod Energy Ltd.
"**Auditors**"	Ernst & Young LLP
"**Avner**"	Avner Oil Exploration Limited Partnership
"**Banks**"	the Managers and the Financial Adviser
"**Board**"	the board of directors of the Company
"**BP**"	BP Oil International Limited
"**BP Offtake Agreement**"	the long-term offtake agreement between BP and the Group for the sale and purchase of crude oil from the Prinos, Prinos North and Epsilon fields
"**Bribery Act**"	the UK Bribery Act 2010 c.23
"**CA2006 Scheme**"	a scheme of arrangement under Part 26 of the Act
"**CISA**"	Swiss Federal Act on collective investment schemes
"**City Code**"	the UK City Code on Takeovers and Mergers
"**Co-lead Managers**"	Natixis, Poalim IBI Underwriting & Issuing LTD and Société Générale
"**Company**"	Energean Oil & Gas plc
"**Consolidated Historical Financial Information**"	the consolidated historical financial information contained in Section B of Part 13 "*Consolidated Historical Financial Information*"

"**Consortium**"	the consortium of Denison Mines Corporation, Hellenic Petroleum, Wintershall A.G. and White Shield which was the Group's predecessor in the development of the assets in the Prinos basin
"**CPR**"	competent person's report
"**CREST**"	the UK-based system for the paperless settlement of trades in listed securities, of which Euroclear UK and Ireland Limited is the operator
"**CREST Regulations**"	the Uncertificated Securities Regulations 2001 (SI 2001/3755)
"**CSR**"	Corporate Social Responsibility
"**Dalia**"	Dalia Power Energies Ltd
"**Delek**"	Delek Drilling Limited Partnership
"**Directors**"	the Executive Directors and the Non-Executive Directors
"**Disclosure Guidance and Transparency Rules**"	the disclosure guidance and transparency rules produced by the FCA and forming part of the FCA's handbook of rules and guidance as from time to time amended
"Dorad"	Dorad Energy Ltd.
"**EBRD**"	the European Bank for Reconstruction and Development
"**EBT**"	employee benefit trust
"**EBRD Senior Facility**"	the US$75 million senior secured facility from EBRD obtained in May 2016 and amended in July 2016
"**EBRD Subordinated Facility**	the US$20 million subordinated facility from EBRD
"**EEA**"	the European Economic Area
"**EIL Preference Shares**"	preference shares in Energean International
"**EISL**"	Energean Israel Ltd.
"**EISL Class B Shares**"	class B shares in Energean Israel
"**EISL Shareholders' Agreement**"	the shareholders agreement dated 13 June 2017 between Energean E&P Holdings, Kerogen and Energean Israel (as amended)
"**Energean E&P Holdings**"	Energean E&P Holdings Limited
"**Energean International**"	Energean International Limited
"**Energean Israel**"	Energean Israel Limited
"**EOGSA**"	Energean Oil & Gas S.A.
"**EPCIC**"	engineering, procurement, construction, installation and commissioning
"**EPS**"	Early Production Scheme
"**EU**"	the European Union

"**Eurotechniki**"	Eurotechniki Services S.A.
"**Executive Directors**"	the executive Directors of the Company, being those persons named on page 123
"**Existing Shareholders**"	the shareholders of Energean E&P Holdings as of 30 June 2017, including Third Point, Growthy Holdings, Oilco Investments and Adobelero
"**EEZ**"	Israel's Exclusive Economic Zone
"**E&P**"	exploration and production
"**FCA**"	the UK Financial Conduct Authority
"**FDP**"	Field Development Plan
"**FEED**"	front end engineering design
"**Financial Adviser**" or "**Rothschild**"	N. M. Rothschild & Sons Limited
"**Founders**"	Growthy Holdings, Oilco Investments and Adobelero
"**FPSO**"	a floating production, storage and offloading unit which is a vessel used for storing and processing hydrocarbons
"**FSMA**"	the Financial Services and Markets Act 2000, as amended
"**Gas Supply Agreements**"	the gas sale and purchase agreements between Energean Israel and, inter alia Dalia, Or, Israel Chemical and Supergas
"**Global Offer**"	the issue of the New Shares by the Company described in Part 15 "Details of the Global Offer"
"**Governance Code**"	the UK Corporate Governance Code issued by the Financial Reporting Council, as amended from time to time
"**Group**" or "**Energean**"	Energean Oil & Gas plc and each of its consolidated subsidiaries and subsidiary undertakings from time to time
"**Growthy Holdings**"	Growthy Holdings Co. Limited (beneficially owned and controlled by Mathios Rigas)
"**Hellenic Petroleum**"	Hellenic Petroleum S.A.
"**HHRM**"	Hellenic Hydrocarbons Resources Management S.A.
"**HMRC**"	HM Revenue and Customs
"**HSE**"	health and safety and environmental
"**Hydrocarbons Law**"	Greek Law 2289/1995 which, along with the regulations made pursuant to it, has established a legal framework for the regulation of the petroleum industry in Greece
"**IAA**"	the Israel Antitrust Authority
"ICL"	Israel Chemicals Ltd.
"**IEC**"	Israel Electric Corporation Ltd

"**IFRS**"	International Financial Reporting Standards, as adopted by the European Union
"**INGL**"	Israel Natural Gas Lines Ltd
"**IRS**"	United States Internal Revenue Service
"**Initial Wells**"	the three initial wells to be pre-drilled and available at the Karish Main field at first gas
"**Investment Association**"	the trade body that represents UK investment managers
"**Israeli Minister of Energy**"	the Minister with responsibility for, and the head of, the Israeli Ministry of Energy
"**Israeli Ministry of Energy**"	Israeli Ministry of Energy
"**Isramco**"	Isramco Negev 2 LLP
"**IT**"	Information Technology
"**ITA**"	Israeli Tax Authority
"**JOA**"	Joint Operating Agreement
"**Joint Bookrunners**"	Citigroup Global Markets Limited, Morgan Stanley & Co. International plc, RBC Europe Limited, trading as RBC Capital Markets and Stifel Nicolaus Europe Limited
"**Joint Global Co-ordinators**"	Citigroup Global Markets Limited, Morgan Stanley & Co. International plc and Stifel Nicolaus Europe Limited
"**Joint Sponsors"**	Citigroup Global Markets Limited and Morgan Stanley & Co. International plc
"**Karish Lease Environmental Document**"	the documentation prepared by Energean Israel, in accordance with certain specific Israeli governmental guidelines, and which contains the analysis of the results of the offshore environmental baseline survey
"**Karish-1**"	the discovery well drilled at the Karish field by Noble in 2013
"**Kerogen**"	Kerogen Capital and/or Kerogen Investments No. 38 Limited (the holder of shares in Energean Israel)
"**Kerogen Interim Facility**"	the convertible loan extended to the company by Kerogen in December 2016
"**KPIs**"	key performance indicators
"**KOSA**"	Kavala Oil S.A.
"**KWA**"	Kavala Workers' Association
"**Latest Practicable Date**"	15 March 2018, being the latest practicable date before the date of this Prospectus
"**Leases**"	collectively includes concession agreements, oil exploration, development and production licences and leases, and applicable annual work programmes and FDPs

"**Levy**"	levy imposed under the PNR Law
"**LIBOR**"	London Interbank Offered Rate
"**Listing Rules**"	the listing rules of the FCA made under section 74(4) of the FSMA
"**London Stock Exchange**"	London Stock Exchange plc
"**LTIFR**"	lost time incidents frequency rate
"**Major Shareholders**"	Third Point and the Founders
"**Managers**"	the Underwriters, Natixis, Poalim IBI Underwriting & Issuing LTD and Société Générale
"**Market Abuse Regulation**"	Regulation (EU) 596/2014
"**NAPC**"	North Aegean Petroleum Co EPE
"**New Shareholders Agreement**"	the shareholders agreement entered into by the Existing Shareholders on 30 June 2017
"**New Shares**"	new Shares to be allotted and issued as part of the Global Offer
"**NG Law**"	the Israeli Natural Gas Sector Law 5762-2002
"**NGF**"	the Israeli Natural Gas Framework
"**Noble**"	Noble Energy Mediterranean Ltd.
"**Non-Executive Directors**"	the non-executive Directors of the Company
"**NSAI**"	Netherland, Sewell & Associates, Inc.
"**NSAI CPRs**"	the NSAI Ioannina and Montenegro CPR, the NSAI Israeli CPR, the NSAI Katakolo CPR and the NSAI Prinos CPR
"**NSAI Ioannina and Montenegro CPR**"	the CPR prepared by NSAI in respect of the Ioannina field and Blocks 30 and 26
"**NSAI Israeli CPR**"	the CPR prepared by NSAI in respect of the Karish and Tanin assets
"**NSAI Katakolo CPR**"	the CPR prepared by NSAI in respect of the Katakolo asset
"**NSAI Prinos CPR**"	the CPR prepared by NSAI in respect of the Prinos, Prinos North, South Kavala and Epsilon assets
"**OECD**"	Organisation for Economic Co-operation and Development
"**Offer Price**"	the price at which each Share is to be issued pursuant to the Global Offer
"**Official List**"	the Official List of the FCA
"**Oilco Investments**"	Oilco Investments Limited (beneficially owned and controlled by Efstathios Topouzoglou)
"**OPC Hadera**"	OPC Hadera Ltd.
"**OPC Rotem**"	OPC Rotem Ltd.

"**ORL**"	Oil Refineries Ltd.
"**Or Power**"	Or Power Energies
"**Ordinance**"	Israeli Income Tax Ordinance 5721-1961
"**Pan Pacific**"	Pan Pacific Petroleum Pty. Ltd.
"**PCAOB**"	the Public Company Accounting Oversight Board (United States)
"**Petroleum Law**"	Israeli Petroleum Law 5712-1952
"**Petroleum Resources Management System**"	the 2007 SPE/AAPG/WPC/SPEE Petroleum Resource Management System which sets out definitions and guidelines designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements.
"**Petroleum Rights**"	preliminary permits, licences and leases granted under the Petroleum Law
"**Phase 1**"	first phase of development of the Karish and Tanin offshore gas fields
"**PNR Law**"	Taxation of Profits from Natural Resources Law, 5771-2011
"**PRA**"	the United Kingdom Prudential Regulation Authority
"**Pricing Period**"	as defined in the BP Offtake Agreement
"**Prime**"	Prime Marine Corporation
"**Prospectus**"	the final prospectus approved by the FCA as a prospectus prepared in accordance with the Prospectus Rules made under section 73A of the FSMA
"**Prospectus Directive**"	Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in each Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU
"**Prospectus Rules**"	the prospectus rules of the FCA
"**qualified institutional buyers**" or "**QIBs**"	has the meaning given by Rule 144A
"**Qualified Investors**"	persons who are "qualified investors" within the meaning of Article 2(l)(e) of the Prospectus Directive
"**Ramat Gavriel**"	I.P.P. Ramat Gavriel Ltd.
"**Ramat Negev**"	I.P.P. Ramat Negev Energy Ltd.
"**Ratio**"	Ratio Oil Exploration
"**RBL Senior Facility Agreement**"	the reserve based lending agreement signed on 30 January 2018 between EOGSA, as borrower and EBRD, BSTDB, the Romanian ECA and Banca Comerciala Intesa Sanpaolo Romania S.A. as lenders
"**Registrars**"	Computershare Investor Services PLC

"**Regulation S**"	Regulation S under the U.S. Securities Act
"**Relationship Agreements**"	the relationship agreements entered into between the Company and each of Third Point, Growthy Holdings and Oilco Investments as described in Part 9 "*Principal Shareholders and Related Party Transactions—Relationship Agreement with Major Shareholders*"
"**Relevant Member State**"	each member state of the EEA which has implemented the Prospectus Directive (2003/71/EC)
"**Reorganisation**"	the reorganisation of the Company in preparation for the Global Offer as described in paragraph 3 of Part 9 "*Principle Shareholders and Related Party Transactions—Related Party Transactions—Reorganisation in connection with Admission*"
"**Reorganisation Agreement**"	the reorganisation agreement between the Company, Existing Shareholders, Energean E&P Holdings, Energean Israel and Energean International dated 30 June 2017
"**Reporting Accountant**"	Deloitte LLP
"**Rothschild**"	N. M. Rothschild & Sons Limited
"**Rule 144A**"	Rule 144A under the U.S. Securities Act
"**SDRT**"	stamp duty reserve tax
"**Second EISL Subscription Agreement**"	the subscription agreement dated 28 December 2017, based on commercial terms agreed in October 2017, between Energean E&P Holdings, Energean Israel, the Founders and Kerogen
"**Senior Credit Facility**"	the senior credit facility entered into by Energean on 2 March 2018 with a syndicate of lenders to facilitate the implementation of Phase 1 of the Karish and Tanin development
"**Senior Managers**"	those members of the management bodies of the Company and its subsidiaries who are relevant to establishing that the Company has the appropriate expertise and experience for the management of its business for the purposes of item 14.1 of Annex I of the Prospectus Rules, being those persons named in Part 8 "*Directors, Senior Managers and Corporate Governance*"
"**Seven Marine**"	Seven Maritime Company
"**SFA**"	Securities and Futures Act (Cap. 289) of Singapore
"**Shareholders**"	the holders of Shares in the capital of the Company
"**Shares**"	the ordinary shares of the Company, having the rights set out in the Articles
"**SIX**"	the SIX Swiss Exchange
"**SPE Standards**"	the Society of Petroleum Engineers Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information
"**sterling**", "**pounds sterling**", "**GBP**" or "**pence**"	the lawful currency of the United Kingdom

"**Supplementary Agreement**"	the supplementary agreement to the Reorganisation Agreement between the Company, Existing Shareholders, Energean E&P Holdings, Energean Israel and Energean International dated 31 October 2017
"**SURF**"	subsea, umbilicals, risers and flowlines
"**Takeover Offer**"	a takeover offer for the Company made in accordance with the City Code
"**Tamar Lease Partners**"	Noble, Delek, Avner, Isramco and Dor
"**TechnipFMC**"	Technip UK Limited and affiliated entities as the context so requires
"**Third Point**"	Third Point Hellenic Recovery (Lux) S.À R.L.
"**Third Point Director**"	a director on the Board nominated by Third Point
"**Third Point Relationship Agreement**"	the relationship agreement between Third Point and the Company dated 16 March 2018
"**Third Point Shareholder Loan**"	the shareholder loan provided by Third Point to Energean which was discharged pursuant to the Reorganisation Agreement
"**TVDSS**"	true vertical depth subsea
"**UK**"	the United Kingdom of Great Britain and Northern Ireland
"**Underwriters**"	Citigroup Global Markets Limited, Morgan Stanley & Co. International plc, RBC Europe Limited, trading as RBC Capital Markets and Stifel Nicolaus Europe Limited
"**Underwriting Agreement**"	the underwriting agreement entered into between the Company, the Directors, the Major Shareholders and the Underwriters described in paragraph 10.1 of Part 16 "*Additional Information—Underwriting Agreement*"
"**United States**" **or** "**U.S.**"	the United States of America, its territories and possessions, any State of the United States of America, and the District of Columbia
"**U.S. dollars**" **or** "**US$**"	the lawful currency of the United States
"**U.S. Exchange Act**"	United States Securities Exchange Act of 1934, as amended
"**U.S. GAAS**"	auditing standards generally accepted in the United States
"**U.S. Securities Act**"	United States Securities Act of 1933, as amended
"**2010 PD Amending Directive**"	Directive 2010/73/EU

PART 18
GLOSSARY OF TECHNICAL TERMS

The following technical terms are used in this Prospectus. Grammatical variations of these terms should be interpreted in the same way.

2D seismic	seismic data acquired in a single traverse or series of traverses. 2D seismic data provides single cross sections through the subsurface
3D seismic	seismic data acquired as multiple, closely spaced traverses. 3D seismic data typically provides a more detailed and accurate image of the subsurface than 2D seismic data
aeromagnetic data	measurements of the Earth's magnetic field gathered from an aerial survey which is interpreted in order to determine differences between the measured and theoretical values which represent changes in rock type or thickness
aeromagnetic survey	aerial survey of an area performed to collect aeromagnetic data
anticlinal structure	an arched shaped structure in which the strata are convex upwards
API	American Petroleum Institute gravity, a measure of how heavy or light a petroleum liquid is compared to water
appraisal	the phase of petroleum operations immediately following a successful discovery. Appraisal is carried out to determine size, production rate and the most efficient development of a field
appraisal well	a well drilled as part of an appraisal of a field
barrel or bbl	a unit of volume measurement used for petroleum and its products one barrel of oil; one barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = one tonne (approximately depending upon the oil density); 6.29 barrels = one cubic metre
Bcf	billion cubic feet
BCM	billion cubic meters
block	term commonly used to describe areas over which there is a petroleum or production licence or PSC or PSA
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
Brent or Brent crude	a benchmark crude oil from the UK North Sea against which other crude oils are priced. It is widely used as an indicator of the price of oil beyond energy markets. It is traded on forward markets and is the basis of futures and options contracts listed on the International Petroleum Exchange in London
carry	agreement between two parties according to which one of the two agrees to pay for ("**carry**") all or part of the costs attributable to the other, typically conditional on later reimbursement by the latter to the former
charge or migration	the movement of hydrocarbons from source rocks into reservoir rocks. Migration can be local or can occur along distances of hundreds of kilometres in large sedimentary basins, and is a critical to a viable petroleum system

closure	the height from the apex of a reservoir structure to the lowest contour that contains the reservoir structure (spill). Measurements of both the areal closure and the distance from the apex to the lowest closing contour are typically used for the calculations of the estimated hydrocarbon content of a trap
condensate	hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons
contingent resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies
cost recovery	mechanism determined in a PSC or PSA by which the Company (or companies) party to the PSC or PSA is enabled to recover present and past costs
Cretaceous	the final period of the Mesozoic era ranging from approximately 65 to 144 million years ago
dated Brent	a term for a physical cargo of Brent blend crude that has received its loading date range
decommission or decommissioning	the process or the procedure by which the facilities and the infrastructure related to the production of hydrocarbon from an oil field are demobilised and abandoned
dip	the angle at which a rock stratum or structure is inclined from the horizontal
discovery	an exploration well which has encountered oil and gas for the first time in a structure
drilling campaign	a period of time in which drilling activities are performed
dry well	a well which does not encounter hydrocarbons in economically producible quantities
Eocene	the epoch after the Paleocene and before the Oligocene in the Tertiary period from approximately 55.8 million to 33.9 million years ago
EPS	early production scheme. These allow production to begin early while full field development is being planned and permanent facilities are being built. Early production schemes help operators bring their new discoveries on-stream fast.
exploration	the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
exploration well	a well in an unproven area or prospect, may also be known as a "wildcat well"
farm-out	a term used to describe when a company sells a portion of the acreage in a block to another company, usually in return for consideration and for the buying company taking on a portion of the selling company's work commitments

fault . . . . . a displacement (vertical, inclined or lateral) below the earth surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons

field . . . . . a geographical area under which either a single oil or gas reservoir or multiple oil or gas reservoirs lie, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition

FOB . . . . . free on board. FOB prices exclude all insurance and freight charges. Most oil is sold either FOB (effectively priced at the loading port) or CIF (effectively priced at the delivery port)

formation . . . . . a body of rock identified by lithic characteristics and stratigraphic position which is mappable at the earth's surface or traceable in the subsurface

fluid content . . . . . fluid within the pore space of a rock

gas field . . . . . a field containing natural gas but no oil

geological basin . . . . . a depression in the Earth's crust where sediments accumulate

geophysical . . . . . association with the earth science concerned with the physical properties. Geophysical exploration is concerned with measuring the earth's physical properties to delineate structure, rock type and fluid content; these measurements include electrical, seismic, gravity and magnetics

gas oil ratio . . . . . the ratio of the volume of gas to the volume of oil that comes out of solution at standard conditions

hydrocarbon . . . . . a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate

infrastructure . . . . . oil and gas processing, transportation and off-take facilities

Jurassic . . . . . referring to a geologic period of the Mesozoic Era from approximately 199 million to 145 million years ago

kip . . . . . a unit of weight, equal to 1000 pounds

lead . . . . . an identified trap that may contain hydrocarbons. A potential hydrocarbon accumulation may be described as a lead or prospect depending on the degree of certainty in that accumulation. A lead generally requires more data to mature it to the prospect level

lease or licence . . . . . an exclusive right to explore for petroleum, usually granted by a national governing body

LNG . . . . . natural gas that has been liquefied under high pressure and low temperature to reduce its volume to enable easier transportation

LPG . . . . . liquefied petroleum gas

licence area . . . . . the area covered by a licence

Mesozoic . . . . . referring to a geological time range from approximately 252 to 66 million years ago

Miocene . . . . . referring to a geological time frame from approximately 5 to 23 million years ago

MM . . . . . millions

MMbbls . . . . . million barrels

MMboe . . . . . million barrels of oil equivalent

MMscf/day . . . . . million standard cubic feet per day

MMtoe . . . . . million tonnes of oil equivalent

natural gas . . . . . gas, predominantly methane, occurring naturally, and often found in association with crude petroleum

Nm3 . . . . . normal cubic meters

offshore . . . . . that geographic area that lies seaward of the coastline

oil . . . . . a mixture of liquid hydrocarbons of different molecular weights

oil field . . . . . the mapped distribution of a proven oil-bearing reservoir or reservoirs

Oligocene . . . . . the epoch after the Eocene and before the Miocene in the Tertiary period approximately from 34 million to 23 million years ago

onshore . . . . . geographic area that lies landward of the coastline

OPEC . . . . . Organization of the Petroleum Exporting Countries. An intergovernmental organization of 13 nations as of 2017, founded in 1960 in Baghdad by the first five members (Iran, Iraq, Kuwait, Saudi Arabia, Venezuela), and headquartered since 1965 in Vienna.

operator . . . . . the company that has legal authority to drill wells and undertake production of oil and gas. The operator is often part of a consortium and acts on behalf of this consortium

participating interest . . . . . the proportion of exploration and production costs each party will bear and the proportion of production each party will receive, as set out in an operating agreement

petroleum . . . . . a generic name for oil and gas, including crude oil, natural gas liquids, natural gas and their products

petroleum system . . . . . geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal

phase . . . . . a distinct state of matter in a system, e.g. liquid phase or gas phase

pipeline ullage . . . . . available headspace in a pipeline

Platts Urals RCMB differential . . . . . a cash settled future based on the difference between the Platts daily assessment price for Urals RCMB (Recombined) and the Platts daily assessment price for dated Brent

play . . . . . a conceptual model for a style of hydrocarbon accumulation

prospect . . . . . an identified trap that may contain hydrocarbons. A potential hydrocarbon accumulation may be described as a lead or prospect depending on the degree of certainty in that accumulation. A prospect generally is mature enough to be considered for drilling

prospective resources . . . . . those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity

proved reserves . . . . . those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate

PSA or PSC . . . . . production sharing agreement or contract under which the contractor agrees to fund and carry out pre-agreed work programmes on behalf of the concession owner in return for a share of production revenues

reserves . . . . . those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reference should be made to the full PRMS definitions for the complete definitions and guidelines

reservoir . . . . . an underground porous and permeable formation where oil and gas has accumulated

resources . . . . . contingent and prospective resources, unless otherwise specified

rift . . . . . region in which the Earth's crust is pulling apart and creating normal faults and down-dropped areas or subsidence

rig . . . . . the machine used to drill a wellbore

royalty . . . . . a percentage share of production, or the value derived from production, paid from a producing well

seal . . . . . a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system

seismic survey . . . . . a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata

sour . . . . . with respect to oil: oil containing more than 0.5% sulphur and, with respect to gas: gas containing a measurable amount of H_2S

source . . . . . characteristic of organic-rich rocks to contain the precursors to oil and gas, such that the type and quality of expelled hydrocarbon can be assessed

source rock . . . . . a rock rich in organic matter which, if given the right conditions, will generate oil or gas. Typical source rocks, usually shales or limestones, contain at least 0.5% total organic carbon (TOC), although a rich source rock might have as much as 10% organic matter. Access to a working source rock is necessary for a complete petroleum system

stratigraphic level or position . . . . . layer of sedimentary rock

SURF . . . . . subsea, umbilicals, risers and flowlines

sweet . . . . . with respect to oil: oil containing less than 0.5% sulphur and, with respect to gas: gas which contains no measurable amount of H_2S

Tcf . . . . . trillion of cubic feet

Tertiary . . . . . the Tertiary Period is a geological period from approximately 65 million to 2.5 million years ago

TEG . . . . . triethylene glycol

trap . . . . . a configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch outs and reefs). A trap is an essential component of a petroleum system

Triassic . . . . . referring to a geological time frame from approximately 201 to 252 million years ago

TST . . . . . true stratigraphic thickness

TVDSS . . . . . true vertical depth subsea

UGS . . . . . underground gas storage

upstream . . . . . operations stages in the oil and gas industry that involve exploration and production

vug . . . . . a cavity, void or large pore in a rock that is commonly lined with mineral precipitates

ESTIMATES

of

UNRISKED CONTINGENT RESOURCES AND CASH FLOW TO THE ENERGEAN ISRAEL LTD INTEREST

and

UNRISKED GROSS (100 PERCENT) PROSPECTIVE RESOURCES

in

KARISH AND TANIN FIELDS

located

OFFSHORE ISRAEL

as of

OCTOBER 31, 2017

BASED ON ESCALATED PRICE AND COST PARAMETERS

specified by

ENERGEAN ISRAEL LTD

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
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January 5, 2018

Energean Oil & Gas PLC
21 Gloucester Place
London W1U 8HR
United Kingdom

Energean Israel Ltd
B.S.R. 3 Tower, 21st Floor
9, Metsada Street
Bnei Brak, Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked contingent resources and cash flow, as of October 31, 2017, to the Energean Israel Ltd (Energean) interest in Karish and Tanin Fields, offshore Israel. Also as requested, we have estimated the unrisked gross (100 percent) prospective resources, as of October 31, 2017, for these properties. We completed our evaluation on or about the date of this letter. For the contingent resources, this report has been prepared using escalated price and cost parameters specified by Energean, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification and a list of abbreviations used in this report. This report has been prepared for use by Energean Oil & Gas PLC in filing with the London Stock Exchange; in our opinion the assumptions, data, methods, and procedures used in preparation of this report are appropriate for such purpose.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report are contingent upon project sanctioning and financing. The contingent resources in the Karish Field B Sand are further contingent upon sufficient flow testing to establish commercial productivity. The costs required to resolve these contingencies have not been included in this report; estimates of cash flow are based on the assumption that all contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed.

We estimate the unrisked net contingent resources and cash flow to the Energean interest in these fields, as of October 31, 2017, to be:

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Category	Unrisked Net Contingent Resources Gas[1] (BCF)	Unrisked Net Contingent Resources Liquids (MMBBL)	Net Contingent Cash Flow After Levy and Corporate Income Taxes (M$) Total	Net Contingent Cash Flow After Levy and Corporate Income Taxes (M$) Discounted at 10%
Low Estimate (1C)	1,728.5	18.6	2,381,593.7	703,029.5
Best Estimate (2C)	2,356.1	32.8	3,820,475.2	1,185,604.0
High Estimate (3C)	3,088.7	51.7	5,709,709.5	1,670,138.6

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. The liquids volumes shown include condensate and natural gas liquids (NGL). Liquids volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Oil equivalent contingent resources shown in this report are expressed in millions of barrels of oil equivalent (MMBOE), determined using the ratio of 5.8 MCF of gas to 1 barrel of oil.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk.

Gross contingent revenue shown in this report is Energean's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for Energean's share of state royalties, payments to seller, capital costs, abandonment costs, operating costs, and Energean's estimates of oil and gas levy and corporate income taxes. The net contingent cash flow has been discounted at an annual rate of 10 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using price parameters specified by Energean. Gas prices are based on Energean's estimate of a $4.25 per MMBTU future contract price and are adjusted for energy content. Gas prices are escalated 2 percent on January 1 of each year throughout the lives of the properties. Liquids prices are based on Energean's estimates of Brent prices and are adjusted for quality, transportation fees, and market differentials. Liquids prices, before adjustments, along with escalation parameters are shown in the following table:

Period Ending	Liquids Price ($/Barrel)
12-31-2017	60.00
12-31-2018	63.75
12-31-2019	67.63

Thereafter, escalated 2 percent on January 1 of each year.

Operating costs used in this report are based on estimates of Energean, the operator of the properties, and include only direct lease- and field-level costs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. As requested, these costs do not include the headquarters general and administrative

overhead expenses of Energean. Also as requested, operating costs are escalated 2 percent on January 1 of each year throughout the lives of the properties.

Capital costs used in this report were provided by Energean and are based on scoping cost estimates performed by Lloyd's Register Group Limited for well drilling and completion and by TechnipFMC plc for pipelines; a floating production, storage, and offloading vessel (FPSO); and production equipment. As requested, capital cost estimates include the full cost to install a new gas export pipeline near the Israeli coast, although Energean has indicated that Israel Natural Gas Lines has agreed in principal to pay approximately MM$100 toward the installation of this pipeline. Abandonment costs used in this report are Energean's estimates of the costs to abandon the wells, pipelines, FPSO, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. Although we have not performed extensive economic analysis on these prospects, based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the reservoir level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each reservoir, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources and the probability of geologic success (P_g) for these prospects, as of October 31, 2017, to be:

	Unrisked Gross (100%) Prospective Resources						
	Low Estimate		Best Estimate		High Estimate		
Field/Prospect	Gas (BCF)	Liquids (MMBBL)	Gas (BCF)	Liquids (MMBBL)	Gas (BCF)	Liquids (MMBBL)	P_g[(1)] (%)
Karish							
Deep	2.5	2.0	9.0	7.0	32.8	24.9	22
East Block	294.2	3.4	388.9	5.7	504.9	8.7	79
Main Block	222.7	2.3	422.0	4.4	652.7	7.1	74
North Downthrown Block	253.6	2.8	384.4	4.9	539.0	7.6	67
North Upthrown Block	377.6	4.1	595.9	7.3	861.8	11.3	75
Northeast Block	90.2	0.8	202.6	1.8	336.8	2.9	70
Tanin							
Deep	10.1	8.0	48.3	37.8	229.7	178.1	20
Prospect 1	189.8	1.0	250.6	1.3	325.1	1.7	80
Prospect 2	50.4	0.3	66.0	0.3	85.0	0.4	81
Prospect 3	60.2	0.3	79.0	0.4	102.2	0.5	81

(1) P_g shown herein is the volume-weighted average of individual P_g values estimated by reservoir.

The liquids volumes shown include crude oil, condensate, and NGL.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes summary projections of contingent resources and cash flow by category, a technical discussion, and pertinent figures. As requested, we have performed economic analysis on a Karish Field standalone development scenario; this report includes an appendix showing our estimates of the unrisked contingent resources and cash flow to the Energean interest, as of October 31, 2017, in Karish Field for this scenario.

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The contingent resources and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Energean, that the

properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests. The contingent and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energean, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ John R. Cliver
By:
John R. Cliver, P.E. 107216
Vice President

Date Signed: January 5, 2018

/s/ Zachary R. Long
By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: January 5, 2018

JRC:ALA

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NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

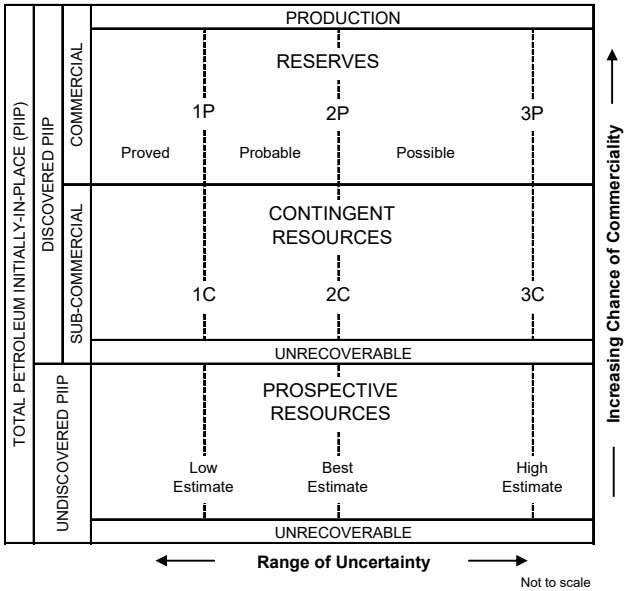


Figure 1-1: Resources Classification Framework.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

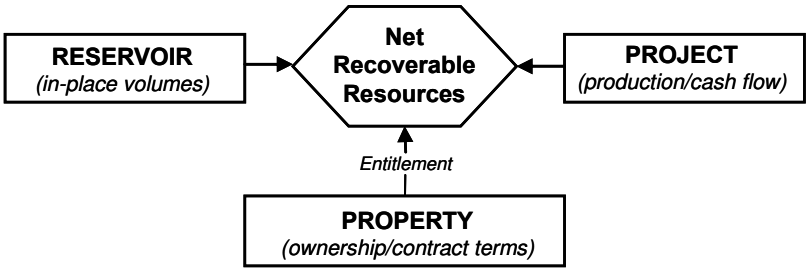


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	**Definition**	**Guidelines**
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	**Definition**	**Guidelines**
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, John R. Cliver, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a contingent and prospective resources evaluation for Energean Oil & Gas PLC. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas PLC or its affiliated companies.

I attended University of Texas at Austin, and I graduated in 2008 with a Master of Business Administration Degree. I attended Rice University, and I graduated in 2004 with a Bachelor of Science Degree in Chemical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 14 years of experience in petroleum engineering studies and evaluations.

/s/ John R. Cliver

By: _____

John R. Cliver, P.E.
Vice President
Texas License No. 107216

January 5, 2018
Houston, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Zachary R. Long, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a contingent and prospective resources evaluation for Energean Oil & Gas PLC. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas PLC or its affiliated companies.

I attended Texas A&M University, and I graduated in 2005 with a Master of Science Degree in Geology. I attended University of Louisiana at Lafayette, and I graduated in 2003 with a Bachelor of Science Degree in Geophysics; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 13 years of experience in petroleum engineering studies and evaluations.

/s/ Zachary R. Long

By: _____

Zachary R. Long, P.G.
Vice President
Texas License No. 11792

January 5, 2018
Houston, Texas

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ABBREVIATIONS

$	United States dollars
Φ	porosity
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
BBL	barrels
BBL/MMCF	barrels per million cubic feet
BCM/y	billions of cubic meters of gas per year
BCF	billions of cubic feet
Energean	Energean Israel Ltd
FPSO	floating production, storage, and offloading vessel
GRV	gross rock volume
GWC	gas-water contact
km	kilometers
m	meters
M$	thousands of United States dollars
MM$	millions of United States dollars
Max	maximum
MCF	thousands of cubic feet
MCF/STB	thousands of cubic feet per stock tank barrel
Min	minimum
ML	most likely
MMBBL	millions of barrels
MMBOE	millions of barrels of oil equivalent
MMBTU	millions of British thermal units
NGL	natural gas liquids
Noble	Noble Energy, Inc.
NTG	net-to-gross ratio
OGIP	original gas-in-place
ohm.m	ohm-meters
P10	10 percent confidence level
P90	90 percent confidence level
P_g	probability of geologic success
PRMS	Petroleum Resources Management System
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
RB/STB	reservoir barrels per stock tank barrel
SCF/RCF	standard cubic feet per reservoir cubic foot
SGS	SGS Oil, Gas & Chemicals Testing Services
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
STB/MMCF	stock tank barrels per million cubic feet
S_w	water saturation
TVDSS	true vertical depth subsea
US$	United States dollars
V_{sh}	shale volume

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SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED LOW ESTIMATE (1C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	2.4	32.8	4.852	78.36	1,045,347.4	114,322.8	73,039.7	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	2.4	32.8	4.949	79.77	1,065,869.3	116,725.6	73,804.6	72,555.2	0.0	69,135.6
12-31-2023	181.1	176.6	2.4	32.8	5.048	81.20	1,086,801.6	119,054.5	74,521.5	194,074.4	0.0	72,970.0
12-31-2024	181.1	176.6	2.4	32.8	5.149	82.66	1,108,152.5	121,367.8	81,463.4	265,342.9	0.0	77,711.5
12-31-2025	181.1	176.6	2.2	32.7	5.225	84.16	1,111,710.8	121,318.5	80,973.7	241,084.1	0.0	82,982.2
12-31-2026	181.1	176.6	2.1	32.5	5.302	85.68	1,115,251.5	121,508.8	80,639.4	21,511.7	0.0	85,000.2
12-31-2027	181.1	176.6	1.8	32.2	5.351	87.23	1,099,221.4	118,985.8	78,771.6	157,991.4	0.0	89,321.6
12-31-2028	181.1	176.6	1.3	31.7	5.371	88.82	1,063,151.8	114,046.9	64,716.4	0.0	0.0	91,108.0
12-31-2029	181.1	176.6	1.0	31.4	5.418	90.44	1,044,286.5	111,174.9	69,112.5	141,545.9	0.0	95,279.9
12-31-2030	108.7	105.9	0.5	18.8	5.498	92.08	627,505.2	70,753.1	44,633.3	0.0	0.0	94,532.3
12-31-2031	34.3	33.4	0.2	5.9	5.608	93.77	201,955.7	22,817.4	14,396.4	0.0	40,376.1	93,644.1
SUBTOTAL	1,772.8	1,728.5	18.6	316.7	5.213	83.67	10,569,253.6	1,152,076.1	777,107.2	2,719,072.0	40,376.1	918,655.3
REMAINING	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	125,198.1	0.0
TOTAL	1,772.8	1,728.5	18.6	316.7	5.213	83.67	10,569,253.6	1,152,076.1	777,107.2	2,719,072.0	165,574.1	918,655.3
CUM PROD	0.0											
ULTIMATE	1,772.8											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	1,344,381.5
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	986,272.8
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	703,029.5
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	518,928.6
12-31-2021	582,456.0	0.0	0.0	582,456.0	23.0	144,689.2	437,766.8	-1,019,675.2	-907,089.0	15.0	298,136.4
12-31-2022	733,648.4	0.0	0.0	733,648.4	23.0	148,067.8	585,580.5	-434,094.6	-531,719.8	20.0	38,195.2
12-31-2023	626,181.2	0.0	0.0	626,181.2	23.0	151,185.0	474,996.2	40,901.5	-254,917.7	25.0	-130,702.1
12-31-2024	562,266.9	22.6	190,274.1	371,992.8	23.0	108,998.6	262,994.2	303,895.7	-115,627.9	30.0	-241,128.3
12-31-2025	585,352.2	40.3	298,277.7	287,074.5	23.0	65,270.7	221,803.8	525,699.5	-8,833.3	35.0	-313,246.7
12-31-2026	806,591.4	46.8	308,766.0	497,825.4	23.0	62,369.7	435,455.7	961,155.2	181,770.6	40.0	-359,826.2
12-31-2027	654,150.9	46.8	224,289.8	429,861.1	23.0	73,856.4	356,004.7	1,317,159.9	323,431.8		
12-31-2028	793,280.4	46.8	102,122.9	691,157.5	23.0	94,220.0	596,937.5	1,914,097.3	539,314.5		
12-31-2029	627,173.3	14.4	90,321.3	536,852.0	23.0	87,496.4	449,355.6	2,363,452.9	687,050.5		
12-31-2030	417,586.5	40.8	207,125.1	210,461.4	23.0	21,344.7	189,116.7	2,552,569.6	743,574.6		
12-31-2031	30,721.8	46.8	76,499.6	-45,777.8	23.0	0.0	-45,777.8	2,506,791.8	731,136.1		
SUBTOTAL	4,961,967.0		1,497,676.5	3,464,290.5		957,498.7	2,506,791.8	2,506,791.8	731,136.1		
REMAINING	-125,198.1		0.0	-125,198.1		0.0	-125,198.1	2,381,593.7	703,029.5		
TOTAL	4,836,769.0		1,497,676.5	3,339,092.4		957,498.7	2,381,593.7	2,381,593.7	703,029.5		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
[2] Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

Table I

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED BEST ESTIMATE (2C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	3.2	33.6	4.852	78.36	1,106,648.9	124,887.8	77,037.4	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	3.2	33.6	4.949	79.77	1,128,271.6	127,490.2	77,879.9	0.0	0.0	68,309.3
12-31-2023	181.1	176.6	3.2	33.6	5.048	81.20	1,150,326.8	130,144.7	78,749.3	0.0	0.0	69,675.5
12-31-2024	181.1	176.6	3.2	33.6	5.149	82.66	1,172,823.1	132,787.7	86,283.5	75,486.5	0.0	71,928.6
12-31-2025	181.1	176.6	3.2	33.6	5.252	84.16	1,195,769.3	135,356.8	87,223.4	201,915.0	0.0	75,917.9
12-31-2026	181.1	176.6	3.2	33.6	5.357	85.68	1,219,174.4	137,912.4	88,149.3	276,062.8	0.0	80,851.1
12-31-2027	181.1	176.6	3.0	33.4	5.436	87.23	1,218,501.4	137,381.6	87,483.7	250,823.9	0.0	86,334.7
12-31-2028	181.1	176.6	2.7	33.2	5.516	88.82	1,217,444.3	137,056.8	76,109.7	22,380.7	0.0	88,432.9
12-31-2029	181.1	176.6	2.5	33.0	5.597	90.44	1,215,888.9	136,665.9	76,049.0	22,828.4	0.0	90,580.5
12-31-2030	181.1	176.6	1.8	32.3	5.618	92.08	1,161,986.7	129,506.2	72,466.0	144,376.8	0.0	94,788.8
12-31-2031	181.1	176.6	1.4	31.9	5.671	93.77	1,133,271.6	125,705.4	76,329.4	0.0	0.0	96,684.6
SUBTOTAL	1,992.0	1,942.2	30.6	365.5	5.313	84.94	12,920,106.8	1,454,895.4	924,795.3	2,618,840.4	0.0	890,474.1
REMAINING	424.5	413.9	2.2	73.6	5.825	97.09	2,627,264.9	306,604.8	192,158.8	150,209.7	177,525.6	404,772.4
TOTAL	2,416.5	2,356.1	32.8	439.1	5.403	85.77	15,547,371.7	1,761,500.2	1,116,954.1	2,769,050.0	177,525.6	1,295,246.5
CUM PROD	0.0											
ULTIMATE	2,416.5											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	2,148,834.0
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	1,603,781.0
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	1,185,604.0
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	920,225.7
12-31-2021	629,194.7	0.0	0.0	629,194.7	23.0	156,015.6	473,179.1	-984,262.9	-882,118.9	15.0	608,831.9
12-31-2022	854,592.1	0.0	0.0	854,592.1	23.0	159,773.7	694,818.4	-289,444.5	-436,726.1	20.0	251,746.5
12-31-2023	871,757.3	0.0	0.0	871,757.3	23.0	163,606.9	708,150.4	418,706.0	-24,054.3	25.0	24,523.1
12-31-2024	806,336.8	29.4	263,429.2	542,907.6	23.0	105,218.5	437,689.1	856,395.0	207,759.3	30.0	-123,119.3
12-31-2025	695,356.2	44.5	404,630.7	290,725.4	23.0	76,180.4	214,545.0	1,070,940.0	311,058.9	35.0	-220,387.1
12-31-2026	636,198.7	46.8	432,483.4	203,715.4	23.0	73,107.3	130,608.1	1,201,548.1	368,227.6	40.0	-284,846.2
12-31-2027	656,477.4	46.8	381,725.7	274,751.7	23.0	64,387.4	210,364.3	1,411,912.4	451,935.6		
12-31-2028	893,464.2	46.8	340,869.8	552,594.4	23.0	72,444.7	480,149.6	1,892,062.0	625,581.9		
12-31-2029	889,765.2	46.8	298,203.7	591,561.5	23.0	80,805.2	510,756.3	2,402,818.3	793,504.9		
12-31-2030	720,848.8	46.8	163,821.0	557,027.7	23.0	96,958.3	460,069.4	2,862,887.7	931,012.5		
12-31-2031	834,552.3	17.1	142,599.8	691,952.5	23.0	134,271.4	557,681.1	3,420,568.8	1,082,542.0		
SUBTOTAL	7,031,101.6		2,427,763.3	4,603,338.4		1,182,769.6	3,420,568.8	3,420,568.8	1,082,542.0		
REMAINING	1,395,993.5		891,568.2	504,425.3		104,518.9	399,906.4	3,820,475.2	1,185,604.0		
TOTAL	8,427,095.2		3,319,331.5	5,107,763.6		1,287,288.5	3,820,475.2	3,820,475.2	1,185,604.0		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
[2] Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED HIGH ESTIMATE (3C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	3.9	34.3	4.852	78.36	1,162,841.9	133,790.4	80,782.5	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	3.9	34.3	4.949	79.77	1,185,473.7	136,518.9	81,672.1	0.0	0.0	68,309.3
12-31-2023	181.1	176.6	3.9	34.3	5.048	81.20	1,208,558.2	139,302.0	89,513.8	0.0	0.0	69,675.5
12-31-2024	181.1	176.6	3.9	34.3	5.149	82.66	1,232,104.4	142,140.7	90,603.9	0.0	0.0	71,069.0
12-31-2025	181.1	176.6	3.9	34.3	5.252	84.16	1,256,121.5	145,036.3	91,725.9	0.0	0.0	72,490.4
12-31-2026	181.1	176.6	3.9	34.3	5.357	85.68	1,280,618.9	147,989.7	92,880.2	0.0	0.0	73,940.2
12-31-2027	181.1	176.6	3.9	34.3	5.465	87.23	1,305,606.3	150,933.8	94,022.5	80,106.8	0.0	76,331.3
12-31-2028	181.1	176.6	3.9	34.3	5.574	88.82	1,331,093.4	153,802.2	84,258.7	214,273.8	0.0	80,564.7
12-31-2029	181.1	176.6	3.9	34.3	5.685	90.44	1,357,090.3	156,659.2	85,830.4	292,960.0	0.0	85,799.8
12-31-2030	181.1	176.6	3.6	34.1	5.769	92.08	1,352,313.0	155,724.6	85,482.9	193,988.0	0.0	90,420.8
12-31-2031	181.1	176.6	3.3	33.8	5.854	93.77	1,346,966.6	154,808.6	85,157.7	97,382.8	0.0	93,845.7
SUBTOTAL	1,992.0	1,942.2	42.1	377.0	5.360	85.69	14,018,788.1	1,616,706.4	1,002,965.3	2,503,677.7	0.0	849,416.8
REMAINING	1,175.8	1,146.4	9.6	207.2	6.100	99.53	7,945,374.6	926,784.1	556,244.9	336,843.2	191,267.9	845,928.9
TOTAL	3,167.9	3,088.7	51.7	584.2	5.634	88.25	21,964,162.7	2,543,490.5	1,559,210.2	2,840,520.9	191,267.9	1,695,345.7
CUM PROD	0.0											
ULTIMATE	3,167.9											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	3,058,500.5
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	2,259,257.7
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	1,670,138.6
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	1,307,638.7
12-31-2021	672,740.0	0.0	0.0	672,740.0	23.0	166,404.2	506,335.9	-951,106.1	-858,739.3	15.0	893,859.4
12-31-2022	898,973.4	0.0	0.0	898,973.4	23.0	170,354.5	728,618.9	-222,487.1	-391,679.7	20.0	434,769.5
12-31-2023	910,066.9	3.5	32,487.6	877,579.3	23.0	165,319.0	712,260.2	489,773.1	23,387.1	25.0	150,601.8
12-31-2024	928,290.6	32.5	305,585.2	622,705.4	23.0	106,583.3	516,122.2	1,005,895.3	296,741.3	30.0	-31,567.8
12-31-2025	946,868.9	46.0	440,924.2	505,944.7	23.0	79,613.5	426,331.2	1,432,226.4	502,012.2	35.0	-151,312.7
12-31-2026	965,808.8	46.8	457,543.5	508,265.3	23.0	80,032.4	428,232.9	1,860,459.3	689,454.6	40.0	-231,260.1
12-31-2027	904,211.9	46.8	465,972.6	438,239.4	23.0	82,236.3	356,003.1	2,216,462.4	831,115.2		
12-31-2028	798,194.0	46.8	473,834.9	324,359.1	23.0	84,291.9	240,067.2	2,456,529.6	917,935.6		
12-31-2029	735,840.9	46.8	481,478.8	254,362.0	23.0	86,290.4	168,071.6	2,624,601.2	973,193.0		
12-31-2030	826,696.7	46.8	426,262.3	400,434.4	23.0	78,567.7	321,866.7	2,946,467.9	1,069,394.0		
12-31-2031	915,771.8	46.8	380,492.3	535,279.5	23.0	124,374.1	410,905.4	3,357,373.3	1,181,042.5		
SUBTOTAL	8,046,021.9		3,464,581.4	4,581,440.5		1,224,067.3	3,357,373.3	3,357,373.3	1,181,042.5		
REMAINING	5,088,305.6		2,123,962.4	2,964,343.2		612,006.9	2,352,336.3	5,709,709.5	1,670,138.6		
TOTAL	13,134,327.6		5,588,543.8	7,545,783.7		1,836,074.2	5,709,709.5	5,709,709.5	1,670,138.6		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
[2] Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TECHNICAL DISCUSSION

NETHERLAND, SEWELL & ASSOCIATES, INC.

TECHNICAL DISCUSSION
CONTINGENT AND PROSPECTIVE RESOURCES
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

1.0 GENERAL OVERVIEW

We have estimated the unrisked contingent resources and cash flow, as of October 31, 2017, to the Energean Israel Ltd (Energean) interest in Karish and Tanin Fields, offshore Israel. We have also estimated the unrisked gross (100 percent) prospective resources, as of October 31, 2017, for these properties. For the contingent resources, this report has been prepared using price and cost parameters specified by Energean. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers. As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report are contingent upon project sanctioning and financing. The contingent resources in Karish Field B Sand are further contingent upon sufficient flow testing to establish commercial productivity. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed.

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made.

2.0 REGIONAL GEOLOGY

2.1 BASIN OVERVIEW

Karish and Tanin Fields are located in the Levant Basin of the eastern Mediterranean region, shown on the location map in Figure 1. The eastern extent of the basin is marked by the Levant Transform Zone (Dead Sea Transform), the western edge of the basin is delineated by the Nile Delta Cone and the Eratosthenes Seamount, and the northern border is defined by the Taurus Fault Zone (Cyprian Arc). Deformation of the basin started in the Late Paleozoic, with rifting creating a series of horst-and-graben structures that evolved in several pulses. The rifting was followed by postrift cooling and subsidence of the basin. From the Middle Jurassic to Early Tertiary, the basin was a major depocenter for the area. Late Cretaceous convergence

of the Eurasian and Afro-Arabian Plates may have caused compression of the Levant Basin margin and triggered the formation of a fold belt known as the Syrian Arc in the northeast corner of the basin. Reactivation, in a reverse motion, of normal faults created during the rifting stage accentuated the existing anticlines.

Uplift to the east of the Levant Basin and to the south on the Arabian Platform is evidenced by an Eocene regional unconformity. This unconformity separates the older carbonate section from the overlying Oligo-Miocene siliciclastics and marks the onset of widespread erosion, canyon development, and basinward transport of sediments onto the shelf and into older parts of the basin. The Oligo-Miocene sediments are capped by a thick Upper Miocene halite and anhydrite deposit formed during a major drop in sea level. This deposit is, in turn, covered by a Plio-Pleistocene fine-grained siliciclastic wedge formed during gradual sea level rise.

2.2 STRATIGRAPHY

Permo-Triassic rocks sit on crystalline basement in nearshore Israel. It is likely that these rocks thin toward the west, such that Early Jurassic shallow marine carbonates are unconformably deposited on top of crystalline basement offshore, as shown in the stratigraphic column in Figure 2. The Jurassic section is only partially penetrated in wells offshore Israel. The oldest penetrated rocks exhibit several cycles of oolitic, pelletal, and intraclast grainstones and skeletal grainstones separated by thin shales. The Zohar Formation carbonates are thought to be approximately Late Bathonian in age and consist of oolitic, pelletal, intraclast, and skeletal grainstones, mudstones, and packstones. Above the Callovian are Oxfordian to Kimmeridgian rocks of the Delta Formation. The basal part of this section is a transgressive unit that marks the end of the Middle Jurassic carbonate platform. The Tithonian Yam Formation conformably overlies the Delta Formation. This unit, interpreted as slope and basin deposits, is composed of dark, laminated shale and siltstone generally barren of fauna.

Unconformably overlying the Yam Formation is the Gevar Am Formation of Early Cretaceous age. This formation is composed of marine shales with conglomerate and sandstone intercalations. The sandstone deposits are thought to represent channel levee and crevasse splay deposits of proximal slope fans, which were deposited during a relative sea level fall caused by tectonic uplift. Uncomformably overlying the Gevar Am Formation is the Talme Yafe Formation, which is a deposit of carbonate debris marked by a coarse conglomerate at the base. The carbonate is thought to be from platform deposits on the shelf that were possibly deposited as debris flows during a pronounced drop in sea level.

The Late Cretaceous is represented by the Negba, Daliya, Ein Zetim, and Ghareb Formations. The basal Negba and Daliya Formations are pelagic chalks thought to represent the drowning of the offshore area during an extensive sea level rise. These pelagic chalks are overlain by a series of chalky limestones that are separated by shales and were deposited during periods of sea level rise that persisted until Middle Miocene time.

From the Eocene to Early Miocene, rapid deepwater deposition took place within the basin, resulting in a sand-rich sequence that contains the Miocene Tamar Sands. These turbidite sands have been demonstrated to be regionally extensive and prolific gas-bearing reservoirs in several discoveries in the basin, including Leviathan and Tamar Fields. These sands also serve as the target reservoirs in Karish and Tanin Fields. Typically, the Tamar Sands package is composed of A, B, and C Sands. The C Sand is significantly thicker than the A and B Sands and is observed to be more consistent in presence and quality across much of the basin. A regional shale marker that sits just above the A Sand interval serves as the seal, while another regionally extensive shale below the C Sand serves as the base of the Miocene. The Upper Oligocene is characterized by a thick, laterally extensive sand commonly referred to as the D Sand. While the D Sand is generally present where the Tamar Sands have been observed, it is typically wet. In Karish Field, there appears to be enough structural column and juxtaposition of the C and D Sands across

many of the faults that the D Sand is likely to be in communication with the Tamar Sands and gas-bearing in the updip portion of the structure.

During Middle Miocene time, sea level dropped abruptly, and erosion and canyon development were renewed. This lowstand is the start of the Messinian salinity crisis in the Mediterranean area and is represented by the Lakhish Formation, a dark, grey-green, silty claystone. The Messinian Mavqim Formation was deposited unconformably above the Lakhish Formation and is a thick evaporitic series found throughout much of the Mediterranean region. The Mavqim Formation is an evaporite sequence composed of halite and anhydrite. It is thought that the Mediterranean area was isolated from the Atlantic Ocean because the sea level curves of the Mediterranean depart from the worldwide sea level curves. The waters in the isolated Mediterranean slowly evaporated, leaving the salts in the large topographic low of the greater Mediterranean Basin.

Sea levels in the Mediterranean again rose during the Pliocene because the feature that was isolating the area was breached, and marine waters again filled the basin. This resulted in the deposition of hemipelagic clays and marls of the Plio-Pleistocene Yafo Formation. Another drop in sea level led to the deposition of potentially gas-bearing turbidite sands. Sea levels again rose, and hemipelagic deposition resumed. As the rate of sedimentation increased, progradation of highstand deposits occurred. In some areas, this resulted in over 1,000 meters (m) of sediment thickness of the Yafo Formation. Closer to the coastline, the Pleshet Formation conformably overlies the Yafo Formation. The Pleshet Formation is a sequence of clays, sands, silts, and marls of Pleistocene age.

2.3 STRUCTURE AND HYDROCARBON MIGRATION

Structural trap formation in the Levant Basin occurred during the Late Cretaceous compressional event with inversion of previous structural lows into structural highs. This created large anticlinal features in pre-Plio-Pleistocene sediments. The discovery wells in Karish and Tanin Fields, along with several other wells in the basin, target these structural highs. Deeper structures are evidenced by seismic data; however, to date they remain largely unexplored. Large faults that extend down to basement serve as conduits for the migration of hydrocarbons into these features. There is some seismic evidence that the later compressional event relaxed between Plio-Pleistocene and recent times, which may suggest a chance for remigration of hydrocarbons from deeper to shallower traps.

3.0 DATA AND METHODOLOGY

All raw data for this evaluation were provided by Energean. For the geologic portion, the pertinent information provided for Karish and Tanin Fields included a 3-D seismic data set, well logs, directional surveys, formation tops, and sidewall core reports. Energean also provided structural interpretations based on the seismic data for both fields and an independent petrophysical analysis of the well log and sidewall core data for Karish Field. In addition to the geologic data, Energean also supplied formation test and fluid sample data for both fields, as well as its dynamic simulation models for Karish Field.

Deterministic methods were used to derive estimates of contingent resources based on the structural and petrophysical interpretations. For prospective resources, probabilistic methods were used with ranges for the inputs based on findings from the penetrated fault blocks.

3.1 GEOLOGY, GROSS ROCK VOLUME, AND PETROPHYSICS

The seismic data were reviewed against existing structural interpretations for each field. When a discrepancy was identified, minor changes were made to produce a final product that accurately represents the data. Ultimately, the structural interpretations were used along with fluid contacts to define best estimate input values for gross rock volume (GRV) to use in original gas-in-place (OGIP) calculations. To determine the low and high estimate GRV inputs, the best estimate values were ranged by a selected percentage based on the level of uncertainty represented by the data.

We performed full petrophysical evaluations for both the Karish-1 and Tanin-1 wells based on all available data. The key rock properties evaluated include shale volume (V_{sh}), porosity (Φ), and water saturation (S_w). Because there is generally more than one method to evaluate each property and because uncertainty exists beyond what the available data can resolve, low and high estimate petrophysical realizations were generated for each well in an attempt to quantify a reasonable range of outcomes. The low estimate incorporates a component of dispersed shale and a resistivity-based S_w, and the high estimate uses a capillary pressure-derived S_w. Additionally, the low estimate uses a lower cutoff criterion of 40 percent V_{sh} as compared to 50 percent in the high estimate when calculating net-to-gross ratios (NTGs). Both low and high interpretations use 12 percent Φ and 65 percent S_w cutoffs. The net pay, Φ, and S_w for the best estimate interpretation were defined as the average of the low and high estimates.

3.2 PRESSURE-VOLUME-TEMPERATURE ANALYSIS

The hydrocarbons in Karish and Tanin Fields are relatively dry gas, with the fluid in Karish Field having a higher liquid content than that in Tanin Field. To estimate gas expansion factors, we used pressure and temperature measurements from the formation test data acquired in each of the discovery wells combined with gas gravity measurements performed on downhole samples.

In order to estimate liquid yields on the produced gas, we used Petroleum Expert's PVTP software to simulate the single-stage flash conditions using the compositions from the lab reports for the various fluid samples from Karish and Tanin Fields and compared the results of our simulated flash to those measured in the lab. After determining that the liquid yields from the simulated single-stage flash calculations aligned reasonably well with those measured in the lab, we performed simulated multistage flash calculations on the samples to determine the expected liquid yields resulting from the separator train that is currently being designed to process the production from the fields. The separator train assumed in our work included a first stage at 3,626 psia and 68°F and a second stage at 1,160 psia and -4°F. The resulting simulated yields varied depending on which sample composition was used in the analysis. The average reservoir composition will continue to be an uncertainty until either more samples are collected or the field is brought online; therefore, we have captured this range of uncertainty by varying the yields assumed for each resources category.

3.3 ORIGINAL GAS-IN-PLACE

For our deterministic estimates of contingent resources, we selected representative low, best, and high parameters for GRV, NTG, Φ, and S_w. Our intent is that the resulting volumetric OGIP values represent a reasonable 90 percent confidence level (P90), 50 percent confidence level, and 10 percent confidence level (P10) range; therefore, rather than include the full range on each parameter, we applied judgment to the input range such that the resulting OGIP values ranged from P90 to P10 rather than a 99 percent confidence level to a 1 percent confidence level. For the contingent resources, our estimates of volumetric input parameters and of OGIP and ultimate recoveries are shown in Figures 3 and 4, respectively.

For our probabilistic estimates of prospective resources, we used ranges of GRV, NTG, Φ, S_w, and gas expansion factor, but these ranges were applied in a Monte Carlo simulation model. Estimates of hydrocarbons-in-place were then selected from the resulting probabilistic output. Tables of our Monte Carlo input parameters and of our estimates of original hydrocarbons-in-place and unrisked gross (100 percent) prospective resources are shown in Figures 5 and 6, respectively.

3.4 FIELD DEVELOPMENT AND RECOVERY

Karish and Tanin Fields will be developed through subsea production wells, which will be tied back to a floating production, storage, and offloading vessel (FPSO) where fluids will be processed. Dry gas will be sent via export lines to supply the Israeli domestic gas market. We have been provided preliminary design work for these facilities, including scoping costs, which have been incorporated in our contingent cash flows. Karish Field will be developed first and is targeted to produce approximately 5 billion cubic meters of gas per year (BCM/y), or 483 million cubic feet of gas per day. Initially, three wells are expected to be completed in the Karish C Sand. If needed, once the C Sand completions are depleted, the wells will be recompleted to the B Sand. As the Karish Field wells decline after plateau, new wells will be drilled in Tanin Field to maintain 5 BCM/y for as long as possible. As there is additional exploratory potential in Karish and Tanin Fields, the field development drilling plan will be modified to include more wells and completions in the event that additional discoveries are made.

In order to understand the expected flow rates and recovery factors from Karish and Tanin Fields, we built dynamic reservoir simulation models that match the OGIP from our best estimate evaluation. With the FPSO facilities currently planned, we estimate that the minimum wellhead pressure for the subsea wells will be 2,325 psia. We evaluated ranges of uncertainty in various parameters such as effective aquifer size, whether or not the faults are baffling, field permeability, and the residual gas saturation after water influx. The results of this simulation work were used to determine a reasonable range of recovery factors used in our estimates of contingent and prospective resources. The results also provided guidance for the rate profiles used in our contingent cash flows.

3.5 CONTINGENT AND PROSPECTIVE RESOURCES

3.5.1 Contingent Resources

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk. Estimated ultimate recoveries for the contingent resources are shown in Figure 4.

3.5.2 Prospective Resources

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. Estimated ultimate recoveries for the prospective resources are shown in Figure 6.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. A summary of the geologic risking for each prospect is shown in Figure 7.

4.0 KARISH FIELD

4.1 OVERVIEW

Karish Field is located approximately 80 kilometers (km) offshore Israel in the I/17 License where the water depth is approximately 1,700 m. The structure is a large three-way closure that sits on the southern upthrown side of a large down-to-the-north fault and is defined by 3-D seismic data. In 2013, Noble Energy, Inc. (Noble) drilled the Karish-1 well with the intent of targeting the Miocene Tamar Sands. Prior to drilling, it was expected that the C Sand would be present and consistent with the overall quality observed in offset wells. The seismic signature in the shallower A and B Sands indicated that these sands may be thinning as they move up the structure and less likely to be encountered than the C Sand. The well was drilled to a total depth of 4,788 m true vertical depth subsea (TVDSS) and encountered a thick C Sand package. It also encountered a B Sand interval that, while highly laminated and having a lower interpreted NTG than some offset wells, still has the potential to produce a significant volume of hydrocarbons. The A Sand was almost completely shaled out, although more recent interpretations indicate that the sand may have been scoured by younger sediments subsequent to deposition. In either scenario, it is unlikely that the A Sand exists updip of the Karish-1 well; however, there is potential for the sand to thicken downdip. The well logged a gas-water contact (GWC) in the C Sand at 4,511 m TVDSS. The Karish-1 interpreted well log is shown in Figure 8.

4.2 CONTINGENT RESOURCES

Contingent resources were evaluated in the B and C Sands at Karish Field. The C Sand contingent resources are planned for initial development with well completions targeted in the B Sand as the C Sand completions water out.

The seismically mapped structural horizons for each interval were used in the determination of the best estimate GRV. For the downdip limit, the logged GWC of 4,511 m TVDSS was used for both sands. This interpretation is supported by pressure data and observations from offset fields in these same sands. In the B Sand, the low and high estimates of GRV are 10 percent lower and higher, respectively, than the best estimate GRV, because the sand exhibits more lateral variation in the basin and is not imaged clearly enough on the seismic data to provide a more certain structural interpretation. The C Sand is generally more consistent throughout large portions of the basin and is more easily resolved on seismic data to the extent that indications of GWCs can be observed. For these reasons, the low and high estimates of GRV are only 5 percent lower and higher, respectively, than the best estimate GRV for the C Sand. A structure map and gross isopach map for the B Sand are shown in Figures 9 and 10, respectively, and those for the C Sand are shown in Figures 11 and 12, respectively.

The petrophysical cases for the C Sand reflect a relatively narrow range of outcomes because the sand is of generally high quality and less sensitive to the petrophysical interpretation applied. The B Sand is highly laminated and more difficult to evaluate. Standard log analysis methods such as those used in all other reservoirs in this report suggest very little net pay in the B Sand. Energean provided a study of the B Sand that evaluated image log data to identify thin sands that are not effectively resolved by other logging tools. The results suggest that there is significantly more sand in the system than the log-based calculations indicate, although it is highly uncertain how much of the additional sand would contribute to gas production. In an attempt to capture a reasonable range of resources potential in the B Sand, standard log analysis methods were used for the low case and the thin-bed analysis from the image log data was used for the high case.

In the Karish-1 well, three gas samples were collected from the C Sand. These samples varied in composition, ranging from 94 to 96 percent methane. Single-stage flash analysis was performed on the sample with the lowest methane content by SGS Oil, Gas & Chemicals Testing Services (SGS). Weatherford Laboratories (USA) Ltd. and Intertek Westport Technology Center each performed a single-stage flash analysis on the sample with the highest methane content.

We expect the installed facilities to include two stages of separation. After calibrating our pressure-volume-temperature (PVT) models to the lab reports, we calculated condensate yields for the first stage of separation ranging from 9.5 to 15.0 barrels per million cubic feet (BBL/MMCF) of gas produced. We calculated natural gas liquids (NGL) yields for the second stage of separation ranging from 4.0 to 10.0 BBL/MMCF of gas produced. These ranges were applied in our estimates of contingent resources for the C Sand. However, because the fluid in the B Sand appears to have a lower liquid content than the C Sand, our estimates for the B Sand use a lower range.

We have assumed that the contingent resources in Karish Field will initially be produced with three wells completed in the C Sand. Based on the results of simulation models, we estimate that the overall recovery factors from the C Sand will range from 65 to 75 percent. The range of recovery factors used for the B Sand is 55 to 65 percent. There is a chance that gas from the B Sand will flow across faults into the C Sand where there is sand-on-sand juxtaposition and not all wells will need to be recompleted to access the B Sand volumes, but in this report, we have assumed recompletions in all three Karish Field wells.

4.3 PROSPECTIVE RESOURCES

Prospective resources opportunities currently identified within the I/17 License are further discussed below and shown in Figures 13 through 17.

4.3.1 Deep Prospect

The Deep Prospect in Karish Field targets prospective Jurassic reservoirs that are interpreted to be approximately 2,000 m deeper than the discovered reservoirs in the Karish-1 well. According to seismic imaging, a prominent three-way structure is bounded by a large fault to the north, similar to the main structure in Karish Field. Some wells in the nearshore portion of the basin have penetrated Jurassic sections, though no such penetrations exist basinward, which leaves uncertainty regarding reservoir presence and quality. Some thermal maturity studies in the basin suggest that a discovery at this depth would likely be oil-bearing. Because of data limitations for this prospect, we have estimated larger ranges for input parameters and a moderate risk of discovery.

4.3.2 East Block Prospect

The East Block Prospect is situated across a large fault that serves as the eastern boundary of the main Karish Field accumulation. There is no seismic amplitude present in this block; this may be a result of faulting and increased rugosity of the base of overlying salt, both of which can impact seismic data quality. There are no seismic indications regarding GWC depth in this block, so we used an estimate of 4,775 m TVDSS, which is consistent with data observed in the offset prospects and is close to the spill point of this block. This prospect targets only the C and D Sands, as there does not appear to be structural closure in the A and B Sands.

4.3.3 Main Block Prospect

The Main Block Prospect includes the A and D Sands. At the Karish-1 well location, the A Sand has little to no reservoir-quality rock. We believe that reservoir presence and quality may increase farther offstructure because of the development of a paleohigh that limited the extent of A Sand deposition. It would most likely share a common GWC with the B and C Sands of 4,511 m TVDSS. A wide range of GRV and rock properties was used in the probabilistic model to account for uncertainty in the A Sand.

There are also prospective resources estimated within the D Sand. This interval was logged wet in the Karish-1 well; however, based on extensive juxtaposition of the C and D Sands in the updip faults, there is a reasonable chance that these reservoirs are in communication and share a common GWC. Because the D Sand is more regionally consistent than the A Sand, we used a narrower range of petrophysical inputs based on the Karish-1 well log data.

Because of the high probability of geologic success estimated in the D Sand, Energean requested that we prepare an economic scenario that includes production from the D Sand in the Karish Field Main Block Prospect using the same economic parameters as the contingent resources. A summary projection of incremental prospective resources and cash flow is shown in Figure 18.

4.3.4 North Downthrown Block Prospect

The North Downthrown Block Prospect fault block lies across the northern-bounding fault of the main Karish Field accumulation. The seismic imaging is less clear in this block because it is bounded on either side by faulting. The A, B, C, and D Sands in this block are interpreted to have a GWC of 4,775 m TVDSS, based on seismic amplitude in the adjacent upthrown block. Petrophysical input ranges were derived from the corresponding intervals in the Karish-1 well with the exception of the A Sand, which was not present. The A and B Sands are interpreted to have a higher risk of discovery than the C and D Sands, which exhibit better regional presence and better seismic indicators.

4.3.5 North Upthrown Block Prospect

The North Upthrown Block Prospect is located just north of the North Downthrown Block Prospect across a larger fault. This block exhibits a seismic amplitude termination at the C Sand level that is interpreted to indicate a GWC of 4,775 m TVDSS. This block also has similar risks in the A, B, C, and D Sands as in the respective sands in the North Downthrown Block Prospect.

4.3.6 Northeast Block Prospect

Located just east of the North Upthrown Block and North Downthrown Block Prospects, this three-way closure also exhibits a seismic amplitude at the C Sand level that appears to terminate at a similar depth

to that as observed in the North Upthrown Block Prospect. A GWC of 4,775 m TVDSS was estimated for the A, B, and C Sands in this block. There is not enough structural relief for the D Sand structure to climb above the estimated GWC depth. Risking and input parameters are similar to those used in the North Upthrown Block and North Downthrown Block Prospects.

5.0 TANIN FIELD

5.1 OVERVIEW

Tanin Field is located approximately 110 km offshore Israel in the I/16 License where the water depth is approximately 1,800 m. The structure is a southwest-to-northeast-trending anticline that is characterized by a main structure with more steeply dipping flanks and a southern structure that is broader and lower in relief. The field area is covered by the same 3-D seismic data set as Karish Field. In 2012, Noble drilled the Tanin-1 well with the intent of targeting the equivalent Miocene Tamar Sands. Prior to drilling, it was expected that the A and B Sands would be present and gas-filled, although the column height would likely not be sufficient to fill the C Sand. It was expected that reservoir quality in Tanin Field would be similar to nearby discoveries in Leviathan and Tamar Fields. Seismic-based amplitude data provided an indication of a likely GWC in the A Sand. The well was drilled to a total depth of approximately 5,500 m TVDSS and encountered high-quality A and B Sand intervals, both of which were full of gas. The C Sand was penetrated and of good quality but was wet. The well logged lowest known gas at 5,091 m TVDSS in the B Sand, while pressure measurements taken in the well indicated a GWC just below that at 5,095 m TVDSS. An interpreted well log for the Tanin-1 well is shown in Figure 19. The volumes contained in this portion of the field are considered discovered and have been classified as contingent resources. Offset fault blocks that have not yet been penetrated by wells have been identified and have been classified as prospective resources.

5.2 CONTINGENT RESOURCES

Contingent resources were evaluated in the A and B Sands at Tanin Field. All completions are planned in the A Sand, but we expect depletion of the B Sand across faults.

The seismically mapped structural horizons for each interval were used to determine the best estimate GRV. For the best estimate downdip limit, a pressure-based GWC of 5,095 m TVDSS was used for both sands, which is just 4 m deeper than the deepest logged gas. In general, Tanin Field is a lower-relief structure with much less column height than Karish Field, which can cause relatively small changes in velocity modeling to have a more significant impact on the GRV. The low and high estimates of GRV are 10 percent lower and higher, respectively, than the best estimate GRV in the main portion of the field and 20 percent lower and higher, respectively, in the lower-relief southern portion of the field. The rock quality in both the A and B Sands is generally very good. A structure map and gross isopach map for the A Sand are shown in Figures 20 and 21, respectively, and those for the B Sand are shown in Figures 22 and 23, respectively.

In the Tanin-1 well, two gas samples were collected from the A Sand and three gas samples were collected from the B Sand. These samples indicated dry gas with a methane content of approximately 98 percent. Single-stage flash analysis was performed and noted in an SGS lab report of the samples. We followed the same process as for Karish Field to simulate flash calculations in PVT data, and uncertainty in fluid composition led us to apply a range of yields for each resources category. The condensate yields we calculated from the first stage of separation range from 2.5 to 3.5 BBL/MMCF of gas produced, and the NGL yields calculated from the second stage of separation range from 2.0 to 2.5 BBL/MMCF of gas produced. These ranges were applied in our estimates of contingent resources for both the A and B Sands.

We have assumed that the contingent resources in Tanin Field will be produced with six wells completed in the A Sand. The first group of three wells will be drilled and brought online, and then the second group of three wells will be drilled in a different rig campaign as needed to maintain 4 BCM/y production through the facility. Based on the results of these models, we estimate that the overall recovery factors for the A and B Sands from the six wells will range from 62 to 70 percent.

5.3 PROSPECTIVE RESOURCES

Prospective resources opportunities currently identified within the I/16 License are further discussed below and shown in Figures 24 through 26.

5.3.1 Deep Prospect

The Deep Prospect in Tanin Field targets prospective Cretaceous reservoirs that are interpreted to be approximately 1,500 to 2,000 m deeper than the discovered reservoirs in the Tanin-1 well. The portion of the structure that exists within the I/16 License is defined by the 3-D seismic data set, while much of the off-license portion is defined by 2-D seismic data. The Cretaceous section truncates against a large four-way paleohigh southwest of Tanin Field. The northeast flank of the structure extends onto the I/16 License, and only that portion of the overall structure was evaluated for this report. As with the Deep Prospect in Karish Field, there are no well data for this part of the basin, which leaves uncertainty regarding reservoir presence and quality. It is believed that a discovery in this interval would likely be oil. Because of data limitations for this prospect, large ranges have been applied to input parameters. For the same reason, this prospect also carries a moderate risk of discovery.

5.3.2 Prospect 1

Prospect 1 is a fault block that lies just northeast of the main Tanin Field structure. It appears to have a greater column height than the penetrated structure in Tanin Field, though it is less areally extensive. There is good seismic amplitude support in the A Sand that indicates a similar GWC to that measured in the Tanin-1 well at 5,095 m TVDSS. This prospect also targets the B Sand, which is believed to share the same GWC and high-quality rock as the A Sand. Ranges for the petrophysical inputs in the probabilistic model were based on the Tanin-1 well data.

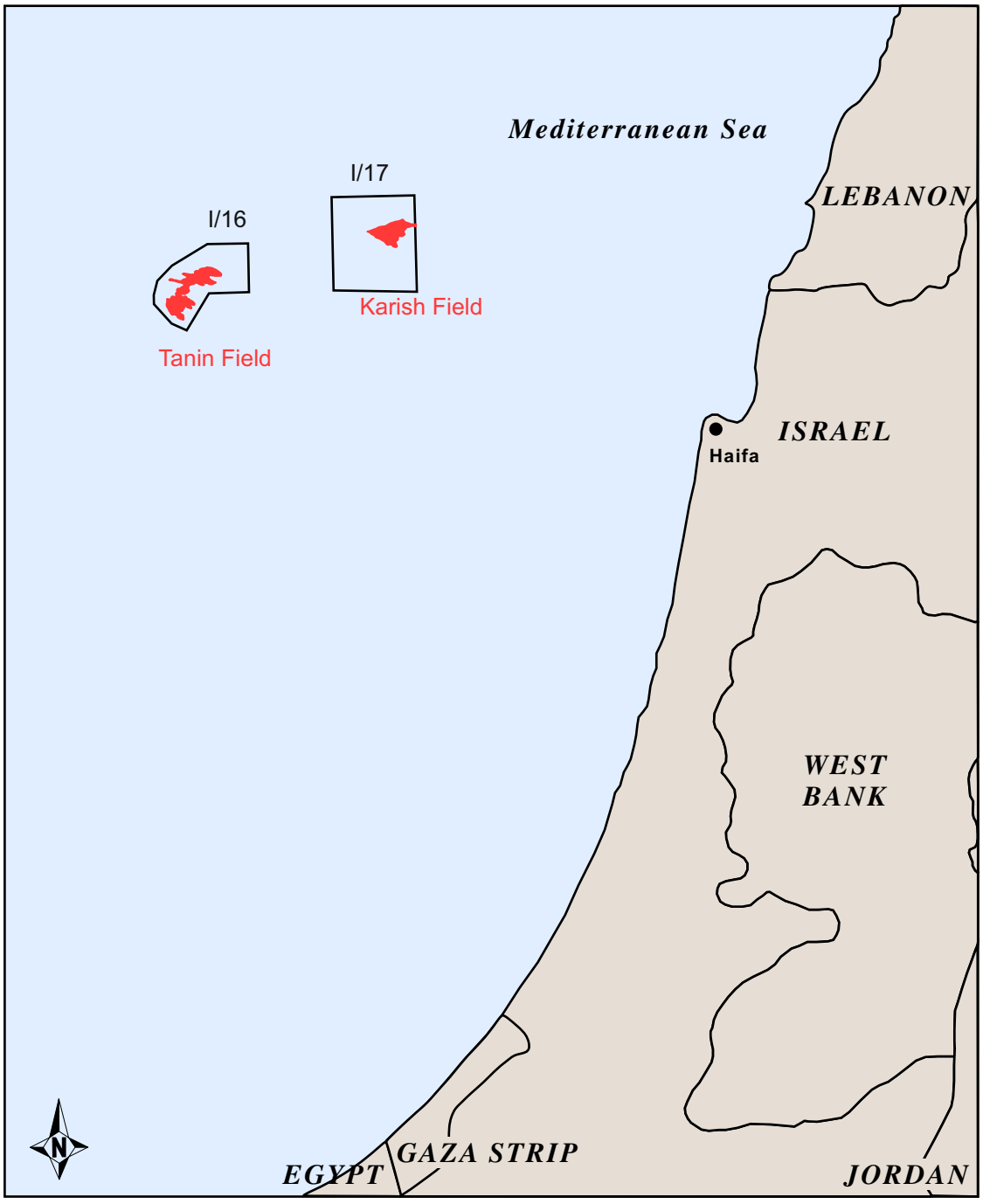
5.3.3 Prospect 2

Prospect 2, located southeast of Prospect 1, primarily targets the A Sand and has an estimated GWC of 5,090 m TVDSS based on seismic amplitude and structural spill. This structural high is bounded to the northeast and southwest by faults. It is a low-relief structure, and we expect that a minimal B Sand structure would be encountered above the GWC. Ranges for the petrophysical inputs in the probabilistic model were based on the Tanin-1 well data.

5.3.4 Prospect 3

Prospect 3, located northeast of Prospect 1, primarily targets the A Sand and has an estimated GWC of 5,070 m TVDSS based on seismic amplitude and structural spill. This structure is low-relief and bounded to the southwest by a fault, suggesting that minimal B Sand volumes may be encountered in this location. Ranges for the petrophysical inputs in the probabilistic model were based on the Tanin-1 well data.

FIGURES



I/16 and I/17 Licenses
Offshore Israel

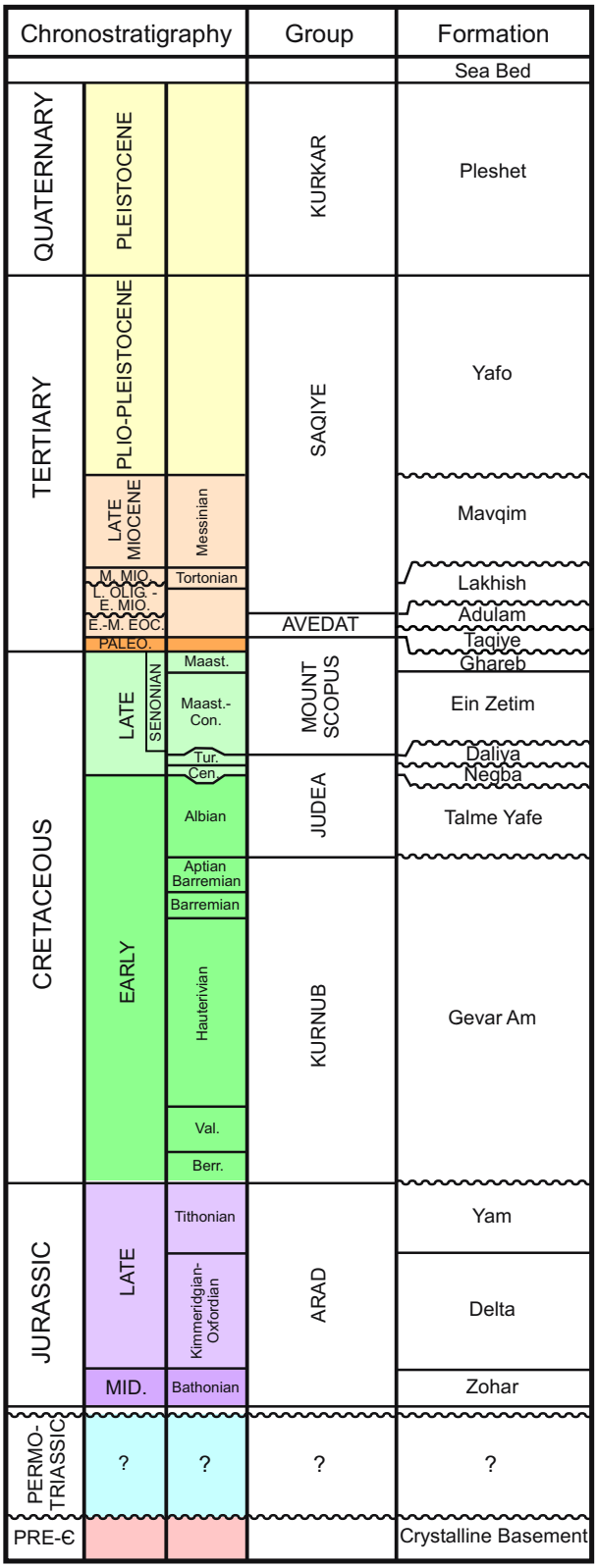
Location Map

SCALE IN METERS
0 12,500 25,000 50,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 1

Stratigraphic Column
Levant Basin
Offshore Israel



Adapted from a figure in "East Mediterranean - Well Data Report", Spectrum Energy and Technology Limited, 2001, p. 53.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

SUMMARY OF VOLUMETRIC PARAMETERS
CONTINGENT RESOURCES
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio[2] (decimal)		
Field/Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Karish												
B	891,094	990,104	1,089,114	6,266	6,962	7,658	142.2	142.2	142.2	0.03	0.14	0.25
C	946,977	996,818	1,046,659	3,650	3,842	4,035	259.4	259.4	259.4	0.64	0.67	0.71
Tanin												
A	504,790	584,741	664,692	9,697	10,774	11,851	52.1	54.3	56.1	0.68	0.74	0.79
B	61,440	68,267	75,094	1,367	1,519	1,671	44.9	44.9	44.9	0.56	0.58	0.61

	Porosity (decimal)			Water Saturation (decimal)			Gas Expansion Factor (SCF/RCF)			Gas Recovery Factor (decimal)		
Field/Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Karish												
B	0.24	0.22	0.19	0.56	0.44	0.31	373	373	373	0.55	0.60	0.65
C	0.23	0.23	0.23	0.20	0.18	0.16	370	370	370	0.65	0.70	0.75
Tanin												
A	0.22	0.22	0.22	0.34	0.29	0.24	374	374	374	0.62	0.66	0.70
B	0.22	0.21	0.21	0.31	0.29	0.27	374	374	374	0.62	0.66	0.70

[1] Average gross thickness is calculated by dividing the gross rock volume by the area.
[2] The Karish C Sand net-to-gross ratios are averages of ratios for the reservoir's three subzones weighted by gross rock volume.

Figure 3

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF UNRISKED ESTIMATED ULTIMATE RECOVERY
CONTINGENT RESOURCES
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Field/Reservoir	Original Gas-in-Place (BCF)			Gas Recovery Factor (decimal)			Unrisked Gas Estimated Ultimate Recovery (BCF)			Liquids Yield (STB/MMCF)			Unrisked Liquids Estimated Ultimate Recovery (MMBBL)		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Karish															
B	52.1	317.6	583.2	0.55	0.60	0.65	28.6	190.6	379.1	4.50	5.25	6.00	0.1	1.0	2.3
C	1,821.6	2,057.4	2,293.1	0.65	0.70	0.75	1,184.1	1,440.2	1,719.8	13.50	19.25	25.00	16.0	27.7	43.0
Tanin															
A	821.0	1,092.1	1,411.0	0.62	0.66	0.70	509.0	720.8	987.7	4.50	5.25	6.00	2.3	3.8	5.9
B	82.6	98.6	116.1	0.62	0.66	0.70	51.2	65.1	81.3	4.50	5.25	6.00	0.2	0.3	0.5

Note: Estimated ultimate recoverable volumes are prior to economic evaluation. Liquids contain condensate and natural gas liquids.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF VOLUMETRIC PARAMETERS
PROSPECTIVE RESOURCES
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Field/ Prospect/Reservoir	Gross Rock Volume (acre-feet)		Gross Rock Volume Distribution Type	Net-to-Gross Ratio (decimal)		Porosity (decimal)		Hydrocarbon Saturation (decimal)		Initial Oil Formation Volume Factor (RB/STB)			Initial Gas Expansion Factor (SCF/RCF)			Average Producing Gas-Oil Ratio (MCF/STB)			Average Producing Liquids Yield (STB/MMCF)			Recovery Factor (decimal)		P_g
	Normal Distribution			Normal Distribution		Normal Distribution		Normal Distribution		Triangular Distribution			Triangular Distribution			Triangular Distribution			Triangular Distribution			Normal Distribution		
	P90	P10		P90	P10	P90	P10	P90	P10	Min	ML	Max	Min	ML	Max	Min	ML	Max	Min	ML	Max	P90	P10	(decimal)
Karish																								
Deep																								
Jurassic	112,439	1,392,330	Lognormal	0.20	0.80	0.10	0.20	0.60	0.80	1.40	1.70	2.00	-	-	-	0.80	1.30	1.80	-	-	-	0.15	0.40	0.22
East Block																								
C	193,154	289,732	Normal	0.60	0.80	0.21	0.24	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.81
D	57,160	85,740	Normal	0.50	0.70	0.20	0.23	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.69
Main Block																								
A	316,956	475,434	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.60
D	195,116	238,476	Normal	0.50	0.70	0.20	0.23	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.85
North Downthrown Block																								
A	48,069	72,103	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.48
B	83,646	125,468	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.60
C	158,418	237,626	Normal	0.60	0.80	0.21	0.24	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.72
D	37,180	55,770	Normal	0.50	0.70	0.20	0.23	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.61
North Upthrown Block																								
A	60,252	90,378	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.54
B	205,059	307,589	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.68
C	221,733	332,599	Normal	0.60	0.80	0.21	0.24	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.81
D	59,958	89,936	Normal	0.50	0.70	0.20	0.23	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.69
Northeast Block																								
A	59,498	89,248	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.54
B	159,423	239,135	Normal	0.10	0.60	0.21	0.24	0.50	0.70	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.68
C	44,778	67,168	Normal	0.60	0.80	0.21	0.24	0.75	0.85	-	-	-	370.0	372.5	375.0	-	-	-	5.00	15.00	25.00	0.55	0.75	0.81
Tanin																								
Deep																								
Cretaceous	461,966	9,985,930	Lognormal	0.20	0.80	0.10	0.20	0.60	0.80	1.40	1.70	2.00	-	-	-	0.80	1.30	1.80	-	-	-	0.15	0.40	0.20
Prospect 1																								
A	127,490	191,236	Normal	0.65	0.85	0.21	0.24	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.81
B	48,225	72,338	Normal	0.50	0.70	0.20	0.23	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.77
Prospect 2																								
A	43,091	64,636	Normal	0.65	0.85	0.21	0.24	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.81
B	362	542	Normal	0.50	0.70	0.20	0.23	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.63
Prospect 3																								
A	51,568	77,352	Normal	0.65	0.85	0.21	0.24	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.81
B	533	799	Normal	0.50	0.70	0.20	0.23	0.65	0.75	-	-	-	370.0	372.5	375.0	-	-	-	4.50	5.25	6.00	0.55	0.75	0.63

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5

SUMMARY OF UNRISKED ESTIMATED ULTIMATE RECOVERY
PROSPECTIVE RESOURCES
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Field/ Prospect/Reservoir	Undiscovered Original In-Place Volumes						Unrisked Estimated Ultimate Recovery						
	Crude Oil (MMBBL)			Gas (BCF)			Liquids[1] (MMBBL)			Gas (BCF)			
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	P_g (decimal)
Karish													
Deep													
Jurassic	7.9	28.3	99.4	-	-	-	2.0	7.0	24.9	2.5	9.0	32.8	0.22
East Block													
C	-	-	-	388.7	484.9	597.3	2.7	4.6	7.0	236.9	312.8	405.1	0.81
D	-	-	-	92.3	117.6	146.6	0.7	1.1	1.7	57.3	76.1	99.8	0.69
Main Block													
A	-	-	-	77.6	295.0	532.6	0.3	1.0	1.8	49.3	189.7	349.4	0.60
D	-	-	-	281.0	359.0	449.2	2.0	3.4	5.2	173.4	232.3	303.3	0.85
North Downthrown Block													
A	-	-	-	12.6	44.5	79.9	0.0	0.1	0.3	8.0	28.7	52.5	0.48
B	-	-	-	21.5	77.1	141.2	0.1	0.3	0.5	13.7	49.6	91.9	0.60
C	-	-	-	318.3	397.8	489.0	2.3	3.8	5.7	195.2	256.5	329.9	0.72
D	-	-	-	59.8	76.7	95.7	0.4	0.7	1.1	36.7	49.5	64.8	0.61
North Upthrown Block													
A	-	-	-	16.8	55.6	101.4	0.1	0.2	0.3	10.8	35.3	66.5	0.54
B	-	-	-	55.3	190.5	344.4	0.2	0.6	1.2	35.0	121.8	225.4	0.68
C	-	-	-	444.3	556.1	685.4	3.2	5.3	8.0	272.2	359.3	465.4	0.81
D	-	-	-	96.6	123.2	154.1	0.7	1.2	1.8	59.6	79.5	104.5	0.69
Northeast Block													
A	-	-	-	15.5	55.6	100.6	0.1	0.2	0.3	9.8	35.7	65.6	0.54
B	-	-	-	40.3	148.1	269.3	0.1	0.5	0.9	25.2	94.3	177.3	0.68
C	-	-	-	90.0	112.6	138.4	0.6	1.1	1.6	55.2	72.7	93.8	0.81
Tanin													
Deep													
Cretaceous	32.5	150.7	705.0	-	-	-	8.0	37.8	178.1	10.1	48.3	229.7	0.20
Prospect 1													
A	-	-	-	243.1	300.9	369.7	0.8	1.0	1.3	148.1	194.4	251.5	0.81
B	-	-	-	67.9	86.8	108.5	0.2	0.3	0.4	41.7	56.2	73.6	0.77
Prospect 2													
A	-	-	-	81.4	101.6	124.6	0.3	0.3	0.4	50.0	65.6	84.4	0.81
B	-	-	-	0.5	0.7	0.8	0.0	0.0	0.0	0.3	0.4	0.6	0.63
Prospect 3													
A	-	-	-	97.4	121.5	149.2	0.3	0.4	0.5	59.8	78.4	101.3	0.81
B	-	-	-	0.8	1.0	1.2	0.0	0.0	0.0	0.5	0.6	0.8	0.63

Note: Totals of unrisked prospective resources beyond the reservoir level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each reservoir, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

[1] Liquids contain crude oil, condensate, and natural gas liquids.

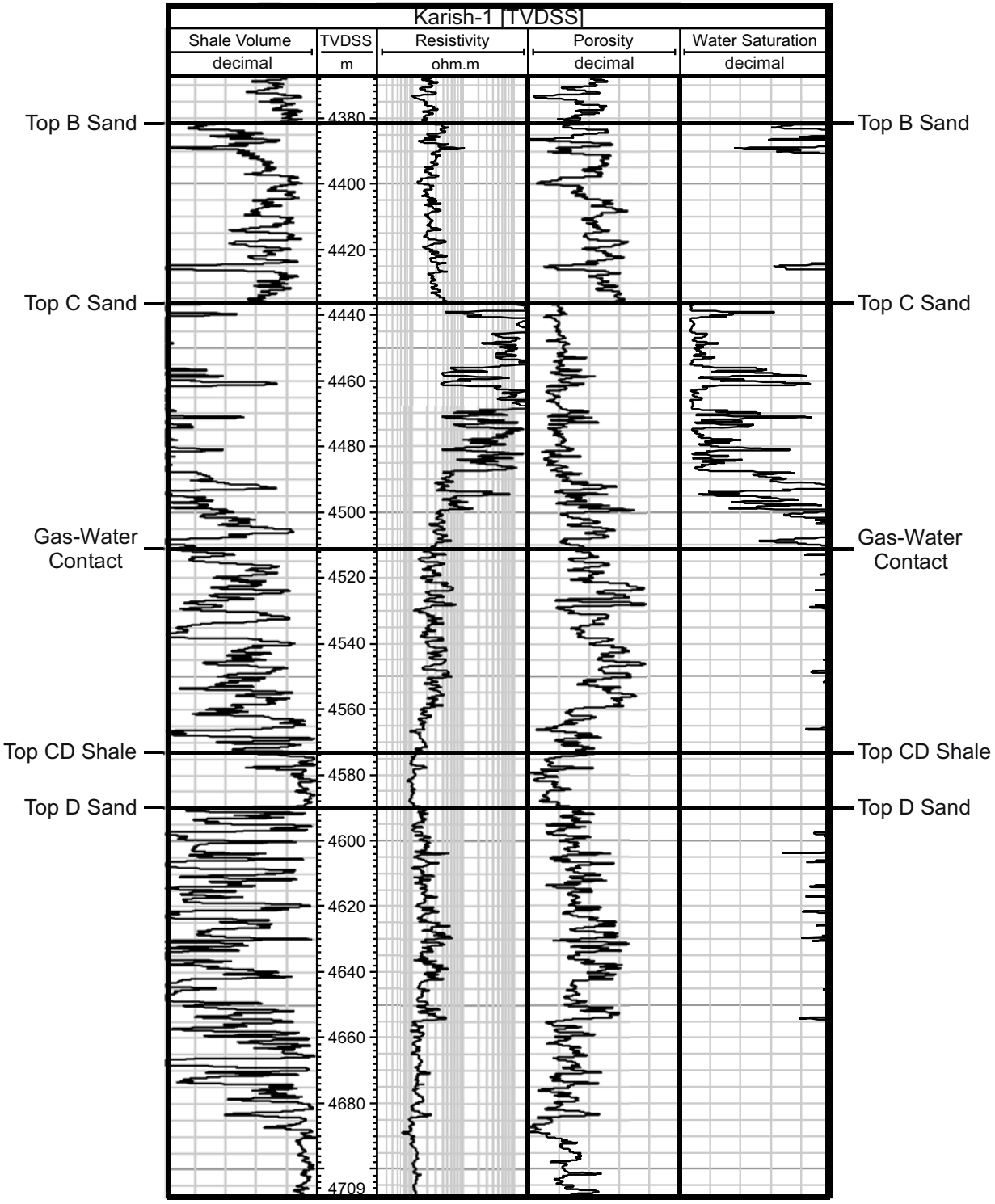
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF GEOLOGIC RISKING
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Field/ Prospect/Reservoir	Geologic Risk Element (decimal) Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	P_g (decimal)
Karish					
Deep					
Jurassic	0.80	0.60	0.60	0.75	0.22
East Block					
C	0.90	0.90	1.00	1.00	0.81
D	0.90	0.90	1.00	0.85	0.69
Main Block					
A	1.00	0.60	1.00	1.00	0.60
D	1.00	1.00	1.00	0.85	0.85
North Downthrown Block					
A	0.80	0.60	1.00	1.00	0.48
B	0.80	0.75	1.00	1.00	0.60
C	0.80	0.90	1.00	1.00	0.72
D	0.80	0.90	1.00	0.85	0.61
North Upthrown Block					
A	0.90	0.60	1.00	1.00	0.54
B	0.90	0.75	1.00	1.00	0.68
C	0.90	0.90	1.00	1.00	0.81
D	0.90	0.90	1.00	0.85	0.69
Northeast Block					
A	0.90	0.60	1.00	1.00	0.54
B	0.90	0.75	1.00	1.00	0.68
C	0.90	0.90	1.00	1.00	0.81
Tanin					
Deep					
Cretaceous	0.75	0.60	0.60	0.75	0.20
Prospect 1					
A	0.90	0.90	1.00	1.00	0.81
B	0.85	0.90	1.00	1.00	0.77
Prospect 2					
A	0.90	0.90	1.00	1.00	0.81
B	0.70	0.90	1.00	1.00	0.63
Prospect 3					
A	0.90	0.90	1.00	1.00	0.81
B	0.70	0.90	1.00	1.00	0.63

Interpreted Well Log
Karish-1 Well - B, C, and D Sands
Karish Field
I/17 License, Offshore Israel



Note: Scales on log curves have been intentionally redacted.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 8

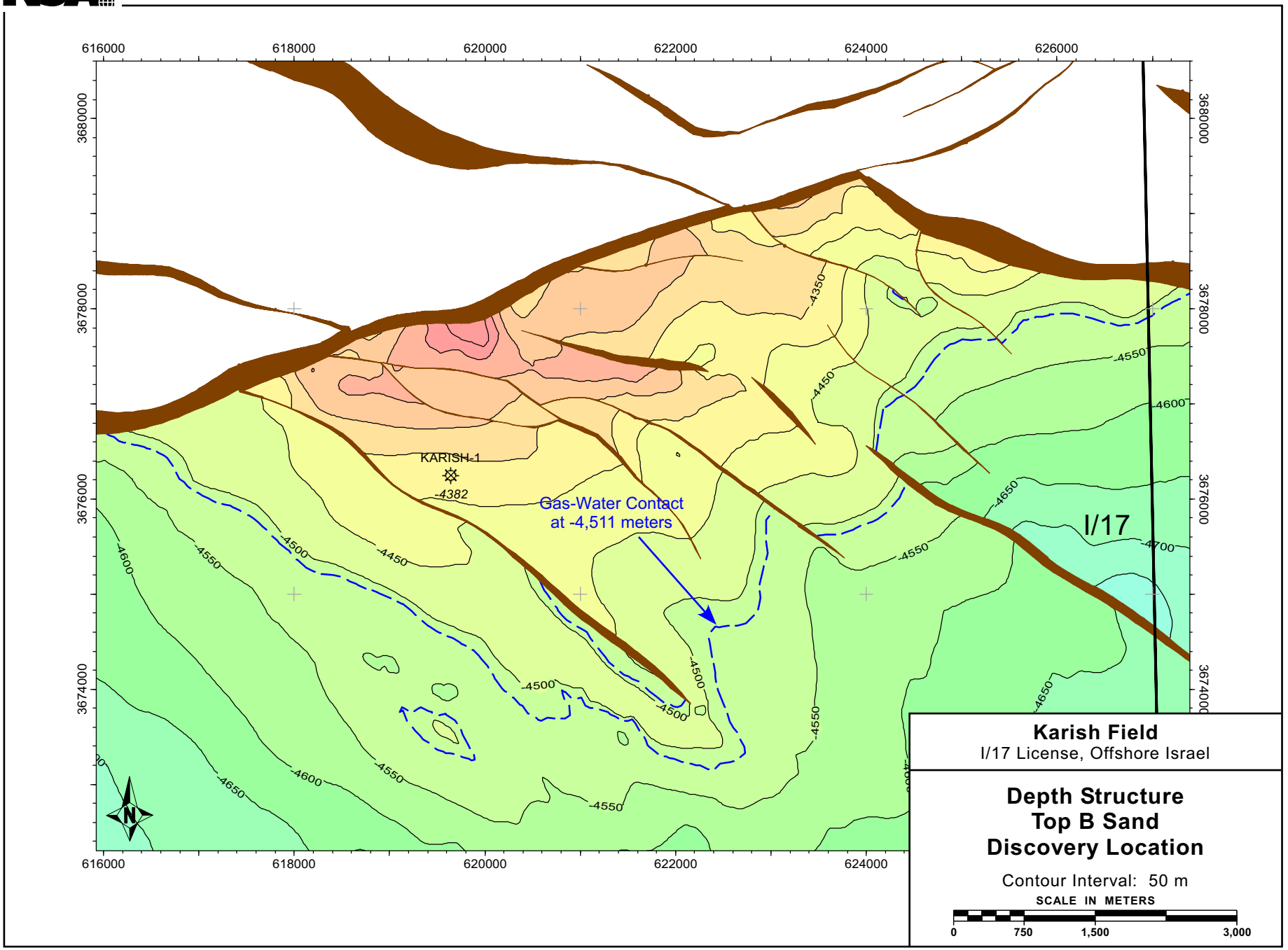


Figure 9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

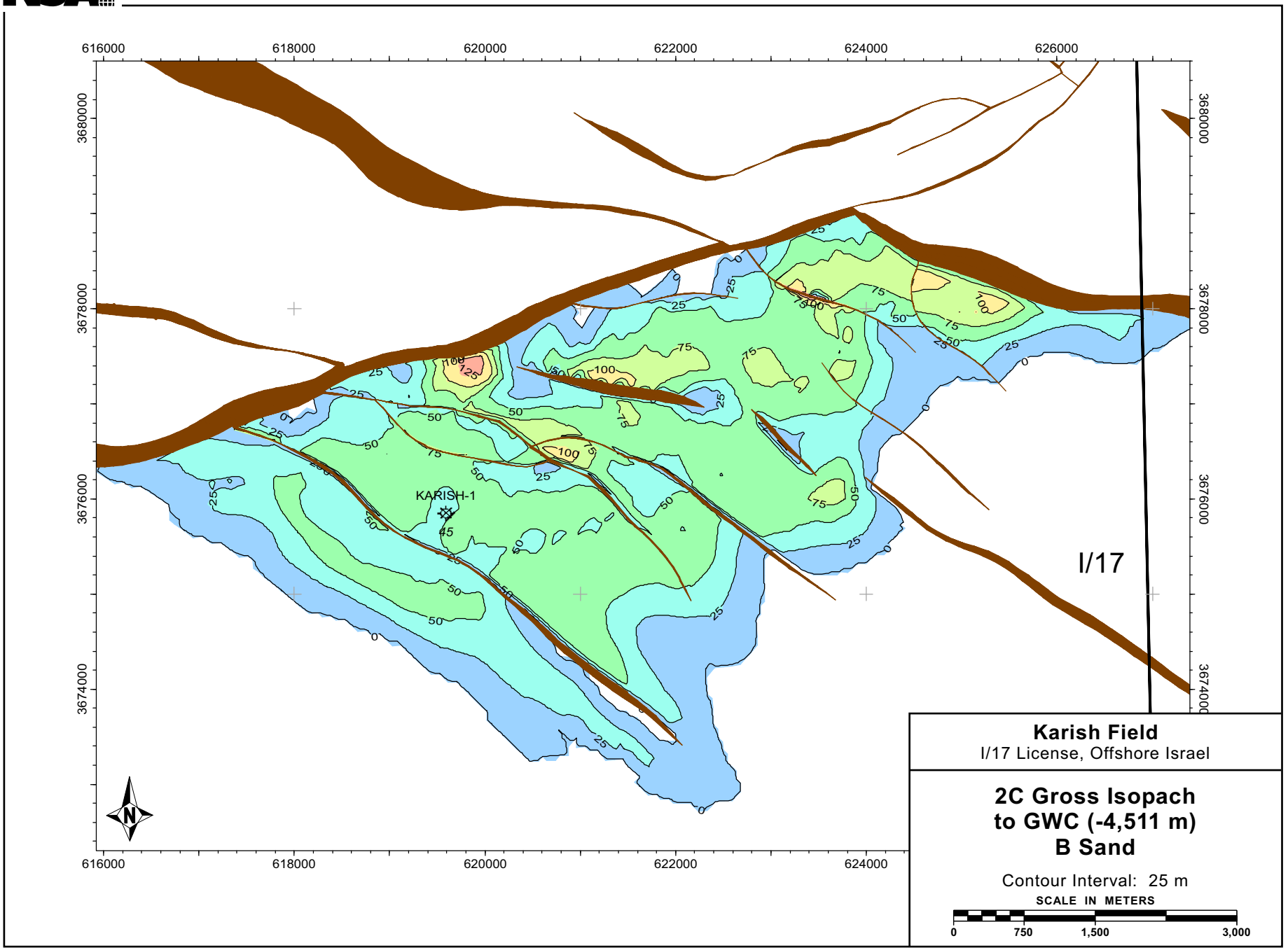


Figure 10

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

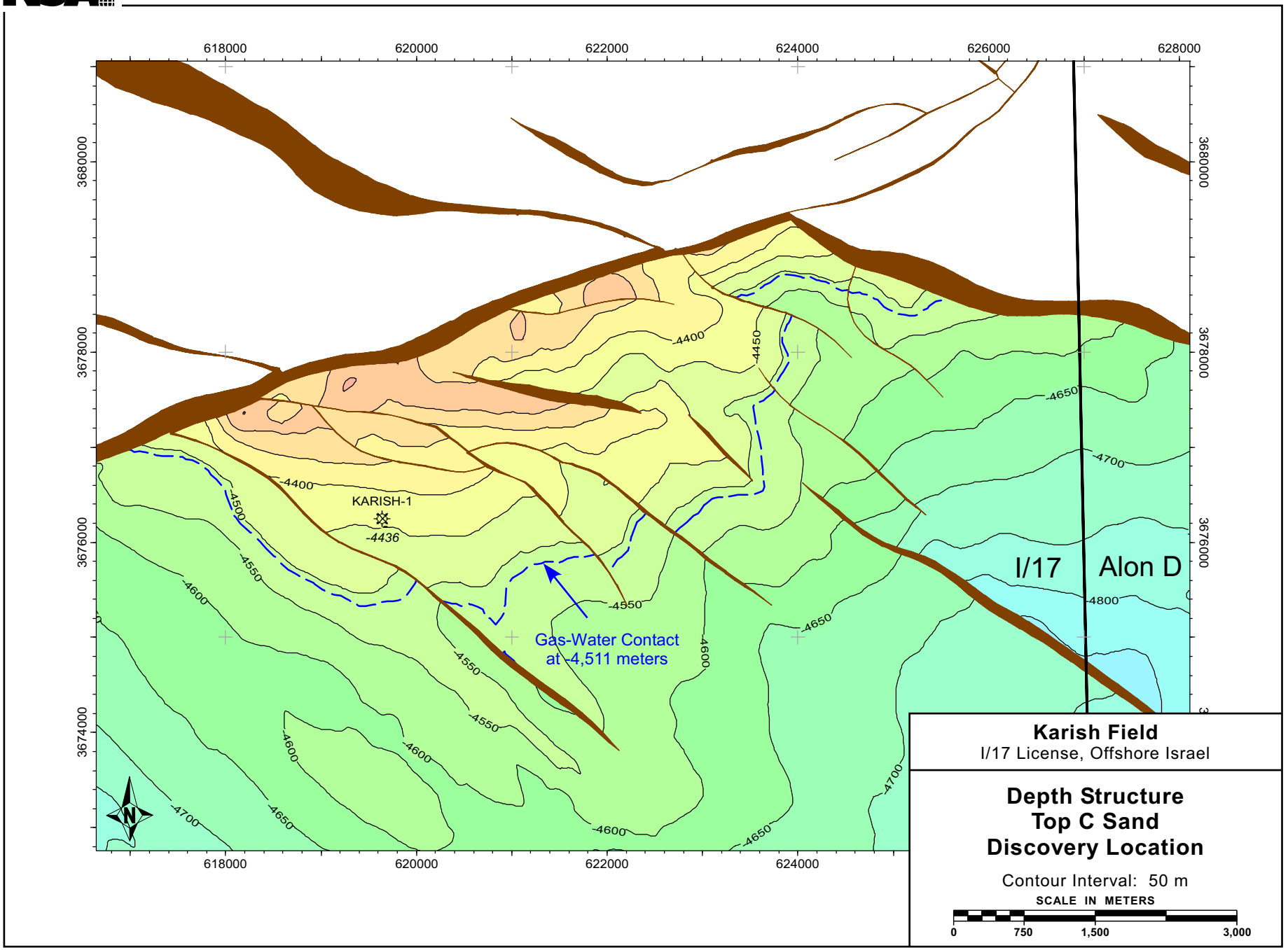


Figure 11

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

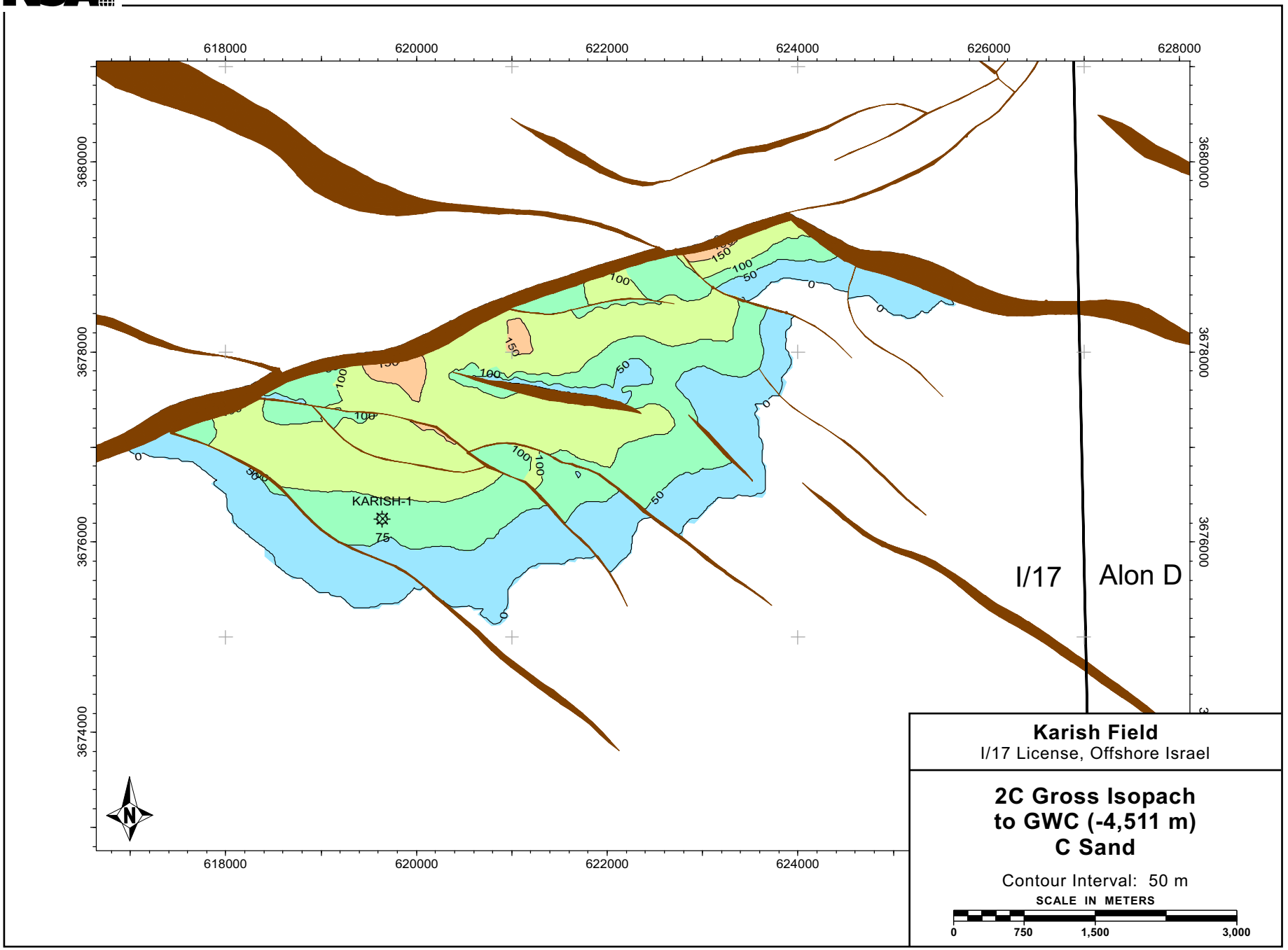


Figure 12

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

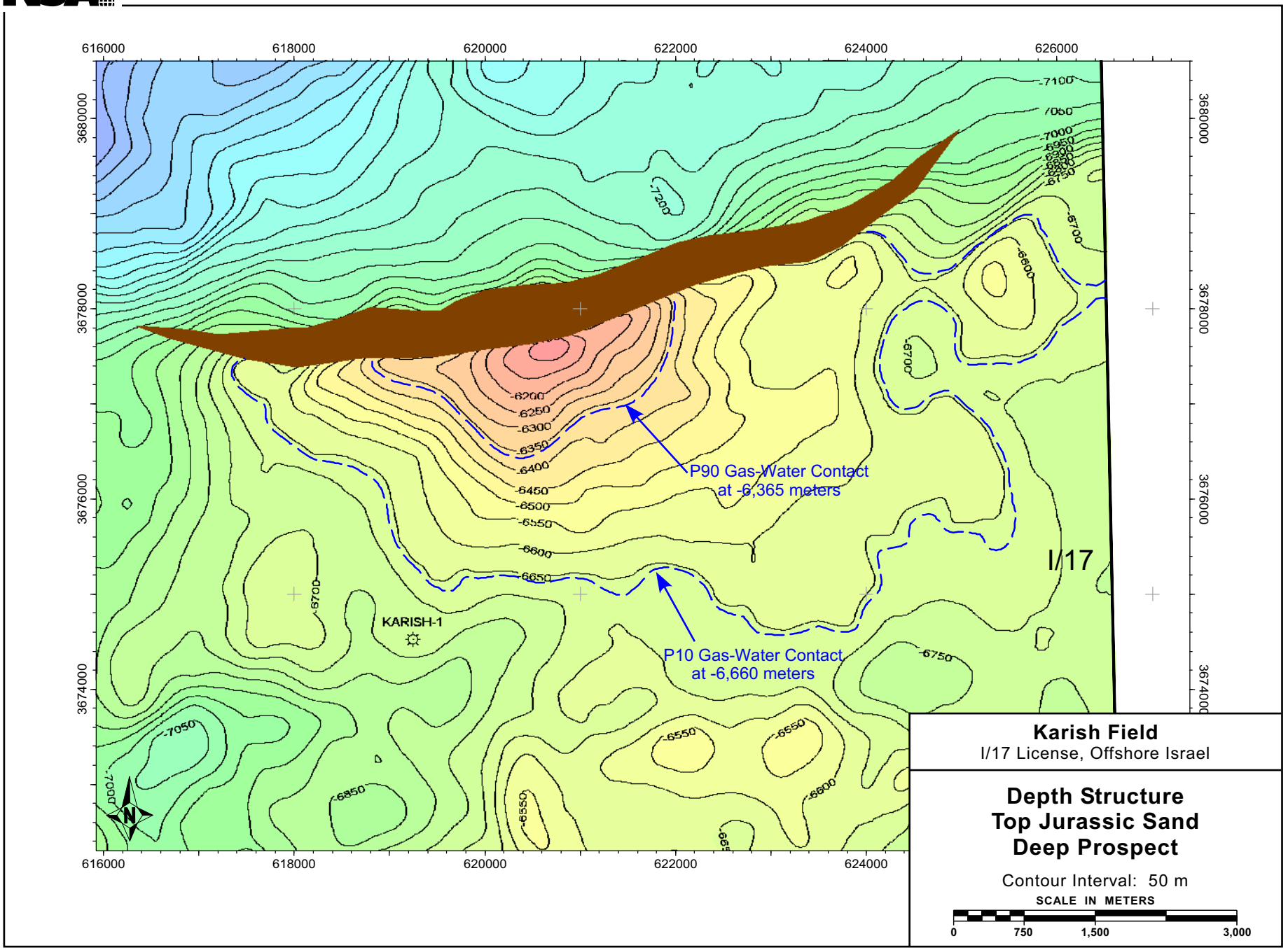


Figure 13

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

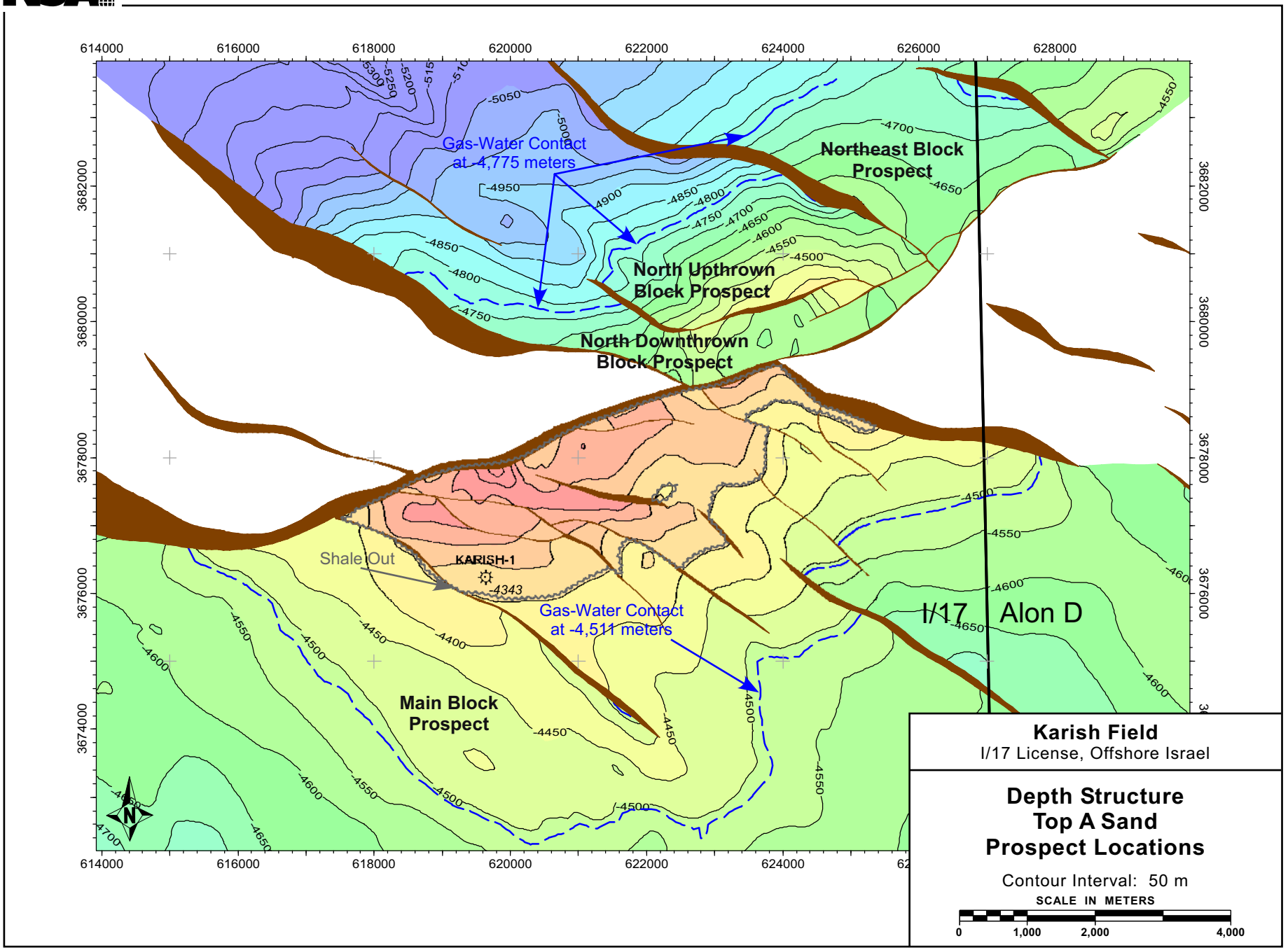


Figure 14

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

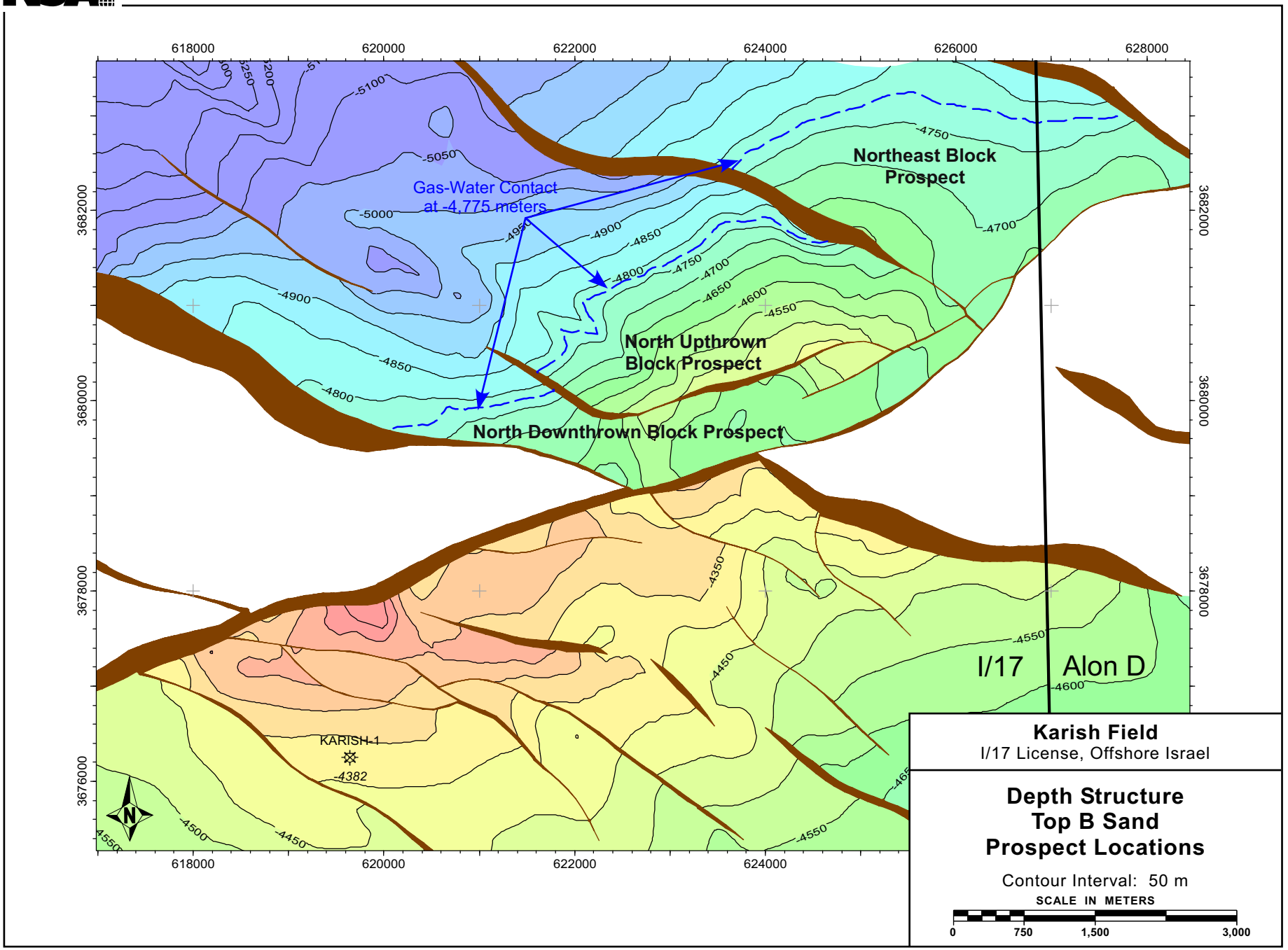


Figure 15

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

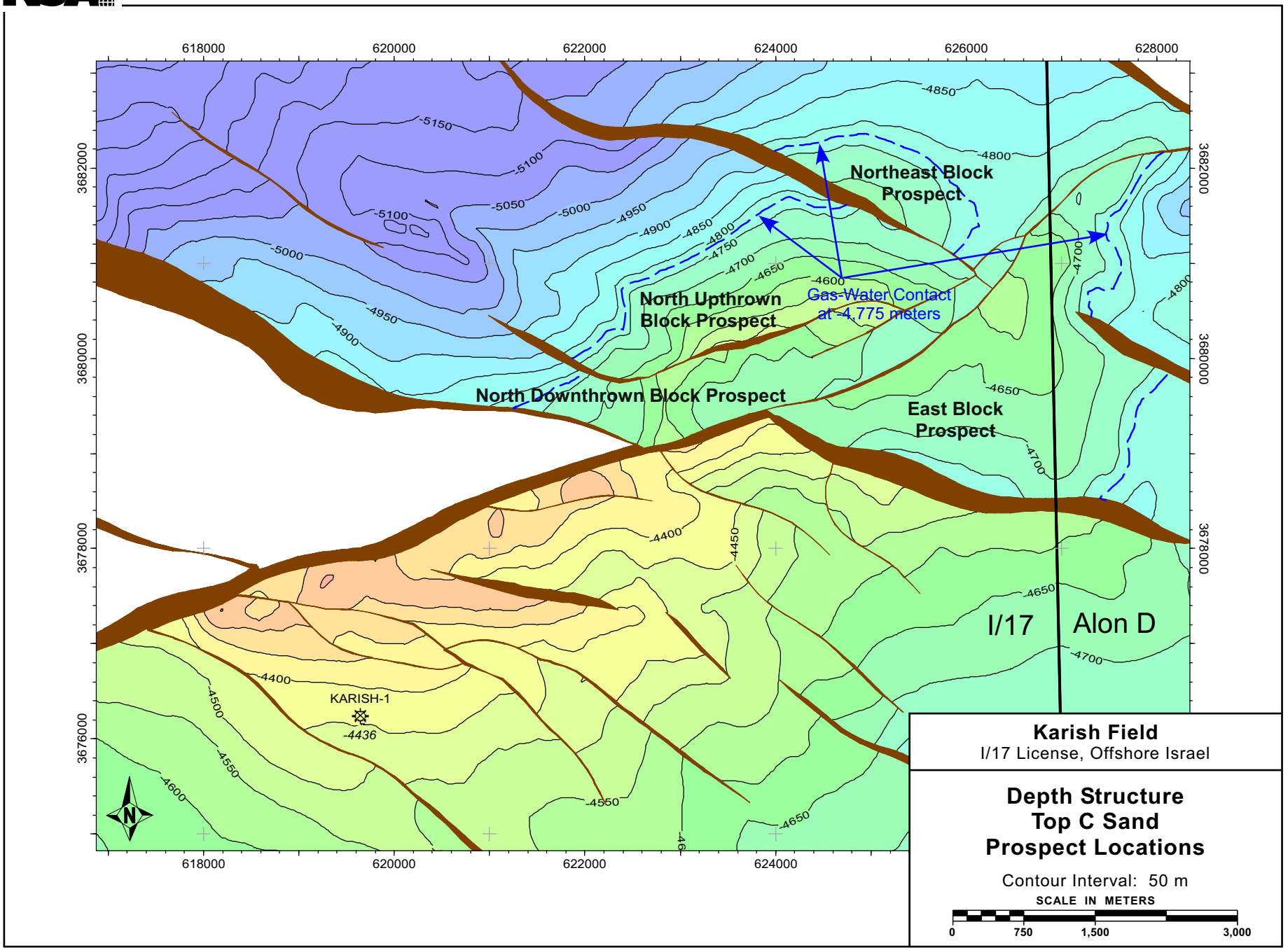


Figure 16

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

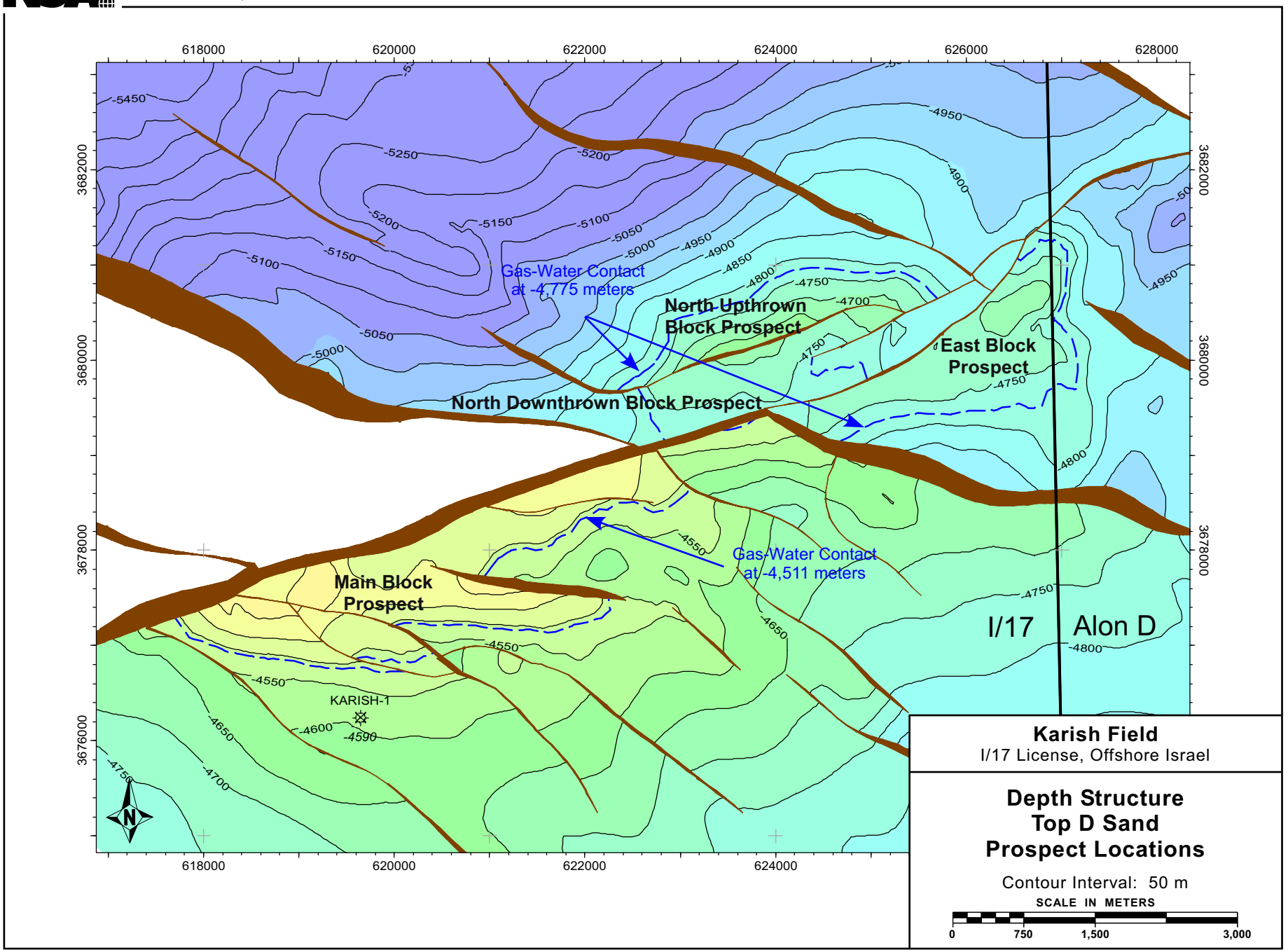


Figure 17

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED INCREMENTAL BEST ESTIMATE PROSPECTIVE RESOURCES[1]
ENERGEAN ISRAEL LTD INTEREST
KARISH AND TANIN FIELDS, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[2] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2021	0.0	0.0	-0.1	-0.1	4.852	78.36	-5,108.5	411.4	512.9	0.0	0.0	0.0
12-31-2022	0.0	0.0	-0.1	-0.1	4.949	79.77	-5,200.2	375.2	496.0	19,873.5	0.0	329.9
12-31-2023	0.0	0.0	-0.1	-0.1	5.048	81.20	-5,293.8	363.0	493.5	0.0	0.0	336.5
12-31-2024	0.0	0.0	-0.1	-0.1	5.149	82.66	-5,389.2	415.1	582.7	-75,486.5	0.0	-516.4
12-31-2025	0.0	0.0	-0.1	-0.1	5.252	84.16	-5,486.6	595.0	707.0	-201,915.0	0.0	-3,077.4
12-31-2026	0.0	0.0	-0.1	-0.1	5.357	85.68	-5,585.9	776.2	832.3	-197,526.7	0.0	-5,659.4
12-31-2027	0.0	0.0	0.2	0.2	5.465	87.23	18,859.1	3,966.7	2,493.1	-40,751.6	0.0	-6,985.5
12-31-2028	0.0	0.0	0.4	0.4	5.574	88.82	44,163.6	6,909.1	3,979.3	287,215.7	0.0	-3,572.4
12-31-2029	0.0	0.0	0.2	0.2	5.685	90.44	20,748.2	3,468.8	2,096.9	238,128.9	0.0	0.0
12-31-2030	0.0	0.0	0.4	0.4	5.799	92.08	48,275.9	6,885.7	3,812.9	-121,091.9	0.0	-2,010.1
12-31-2031	0.0	0.0	0.6	0.6	5.915	93.77	75,025.0	10,161.0	-216.7	0.0	0.0	-2,050.3
SUBTOTAL	0.0	0.0	1.4	1.4	5.368	85.33	175,007.8	34,327.3	15,790.0	-91,553.6	0.0	-23,205.2
REMAINING	232.2	226.4	2.1	41.1	6.094	97.76	1,590,431.0	173,246.1	104,004.9	153,213.9	7,172.0	215,369.9
TOTAL	232.2	226.4	3.4	42.5	5.480	86.80	1,765,438.8	207,573.4	119,794.9	61,660.3	7,172.0	192,164.7
CUM PROD	0.0											
ULTIMATE	232.2											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[3] %	Levy[3] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[3] %	Corporate Income Taxes[3] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	232,784.4
12-31-2018	0.0	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	7.5	174,722.4
12-31-2019	0.0	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	10.0	133,929.9
12-31-2020	0.0	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	12.0	109,854.5
12-31-2021	-6,032.8	0.0	0.0	-6,032.8	23.0	-1,179.0	-4,853.8	-4,853.8	-3,422.5	15.0	83,456.7
12-31-2022	-26,274.8	0.0	0.0	-26,274.8	23.0	-1,720.8	-24,553.9	-29,407.7	-19,162.1	20.0	55,563.6
12-31-2023	-6,486.8	0.0	0.0	-6,486.8	23.0	-1,740.5	-4,746.3	-34,154.1	-21,928.0	25.0	38,862.0
12-31-2024	69,615.9	29.0	-5,293.4	74,909.2	23.0	-381.3	75,290.5	41,136.5	17,948.2	30.0	28,122.4
12-31-2025	198,203.9	44.2	-3,939.5	202,143.4	23.0	-196.0	202,339.4	243,475.8	115,371.0	35.0	20,813.4
12-31-2026	195,991.7	46.8	-718.4	196,710.1	23.0	-436.4	197,146.4	440,622.3	201,664.3	40.0	15,628.1
12-31-2027	60,136.3	46.8	57,274.8	2,861.6	23.0	10,175.3	-7,313.7	433,308.6	198,754.0		
12-31-2028	-250,368.1	46.8	94,516.1	-344,884.3	23.0	5,805.7	-350,690.0	82,618.6	71,926.8		
12-31-2029	-222,946.4	46.8	46,533.0	-269,479.4	23.0	-7,543.3	-261,936.0	-179,317.4	-14,190.7		
12-31-2030	160,679.4	46.8	88,023.6	72,655.9	23.0	-8,549.9	81,205.7	-98,111.7	10,080.4		
12-31-2031	67,131.1	46.8	74,557.8	-7,426.7	23.0	1,521.2	-8,947.9	-107,059.5	7,649.2		
SUBTOTAL	239,649.3		350,953.9	-111,304.6		-4,245.1	-107,059.5	-107,059.5	7,649.2		
REMAINING	937,424.2		212,524.2	724,900.0		177,900.4	546,999.6	439,940.1	133,929.9		
TOTAL	1,177,073.5		563,478.1	613,595.4		173,655.3	439,940.1	439,940.1	133,929.9		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

(1) The unrisked incremental best estimate prospective resources shown are based on a development scenario that includes best estimate (2C) contingent resources. The prospective resources and cash flow shown reflect additional volumes from the Karish Field Main Block Prospect D Sand as well as economic-model-level differences between the two development plans.

(2) Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.

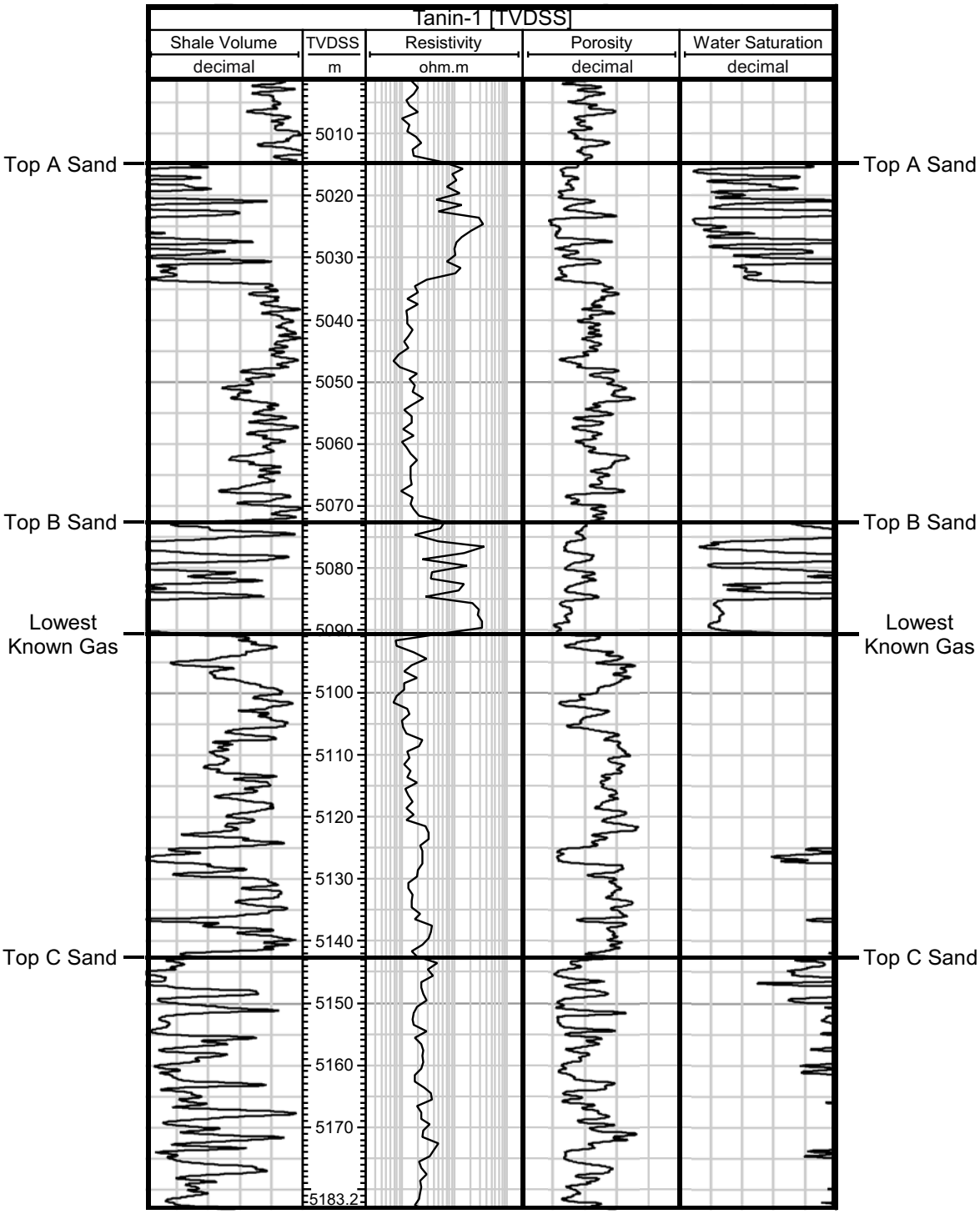
(3) Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

Figure 18

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Interpreted Well Log
Tanin-1 Well - A, B, and C Sands
Tanin Field
I/16 License, Offshore Israel



Note: Scales on log curves have been intentionally redacted.

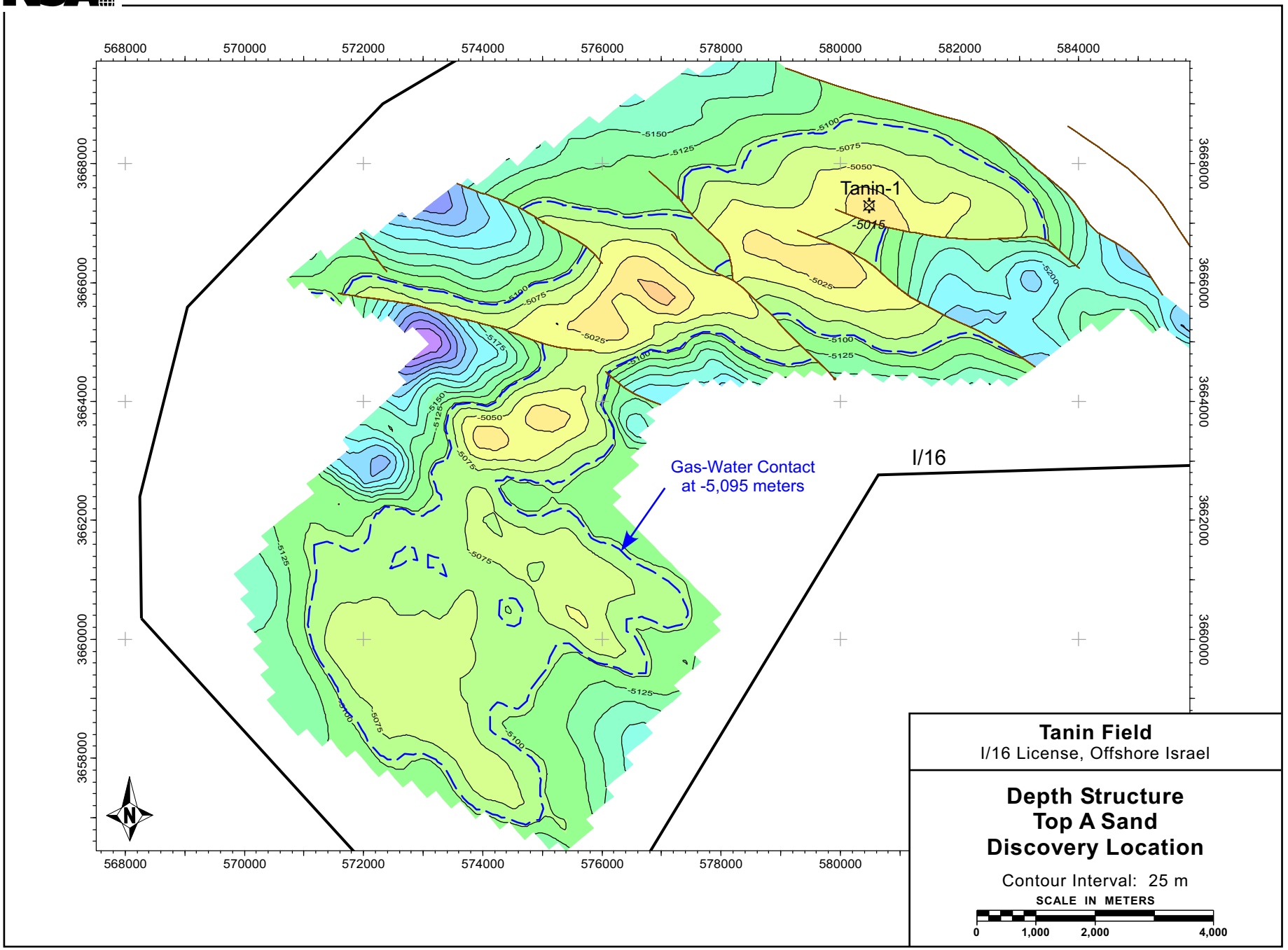


Figure 20

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

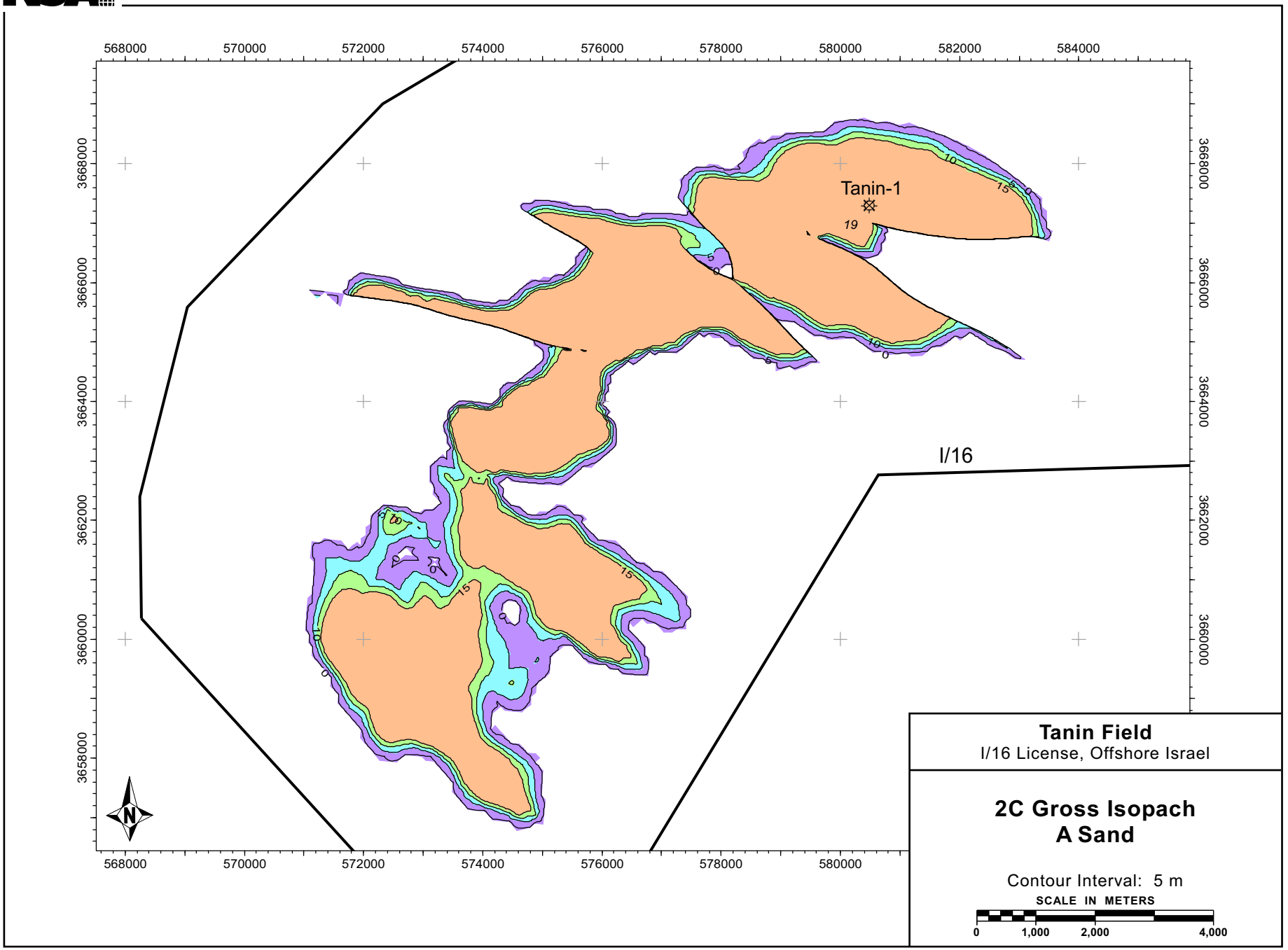


Figure 21

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

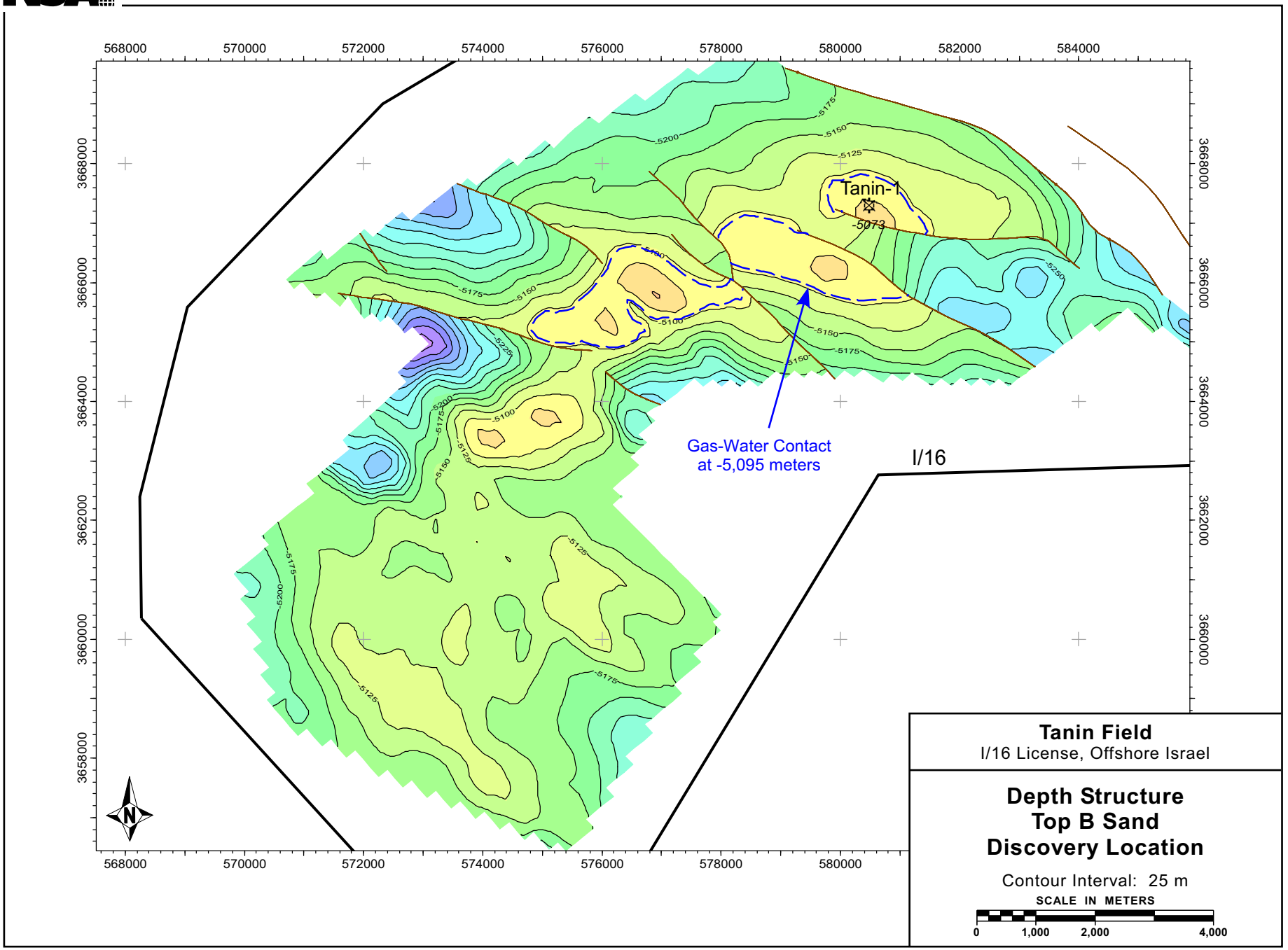


Figure 22

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

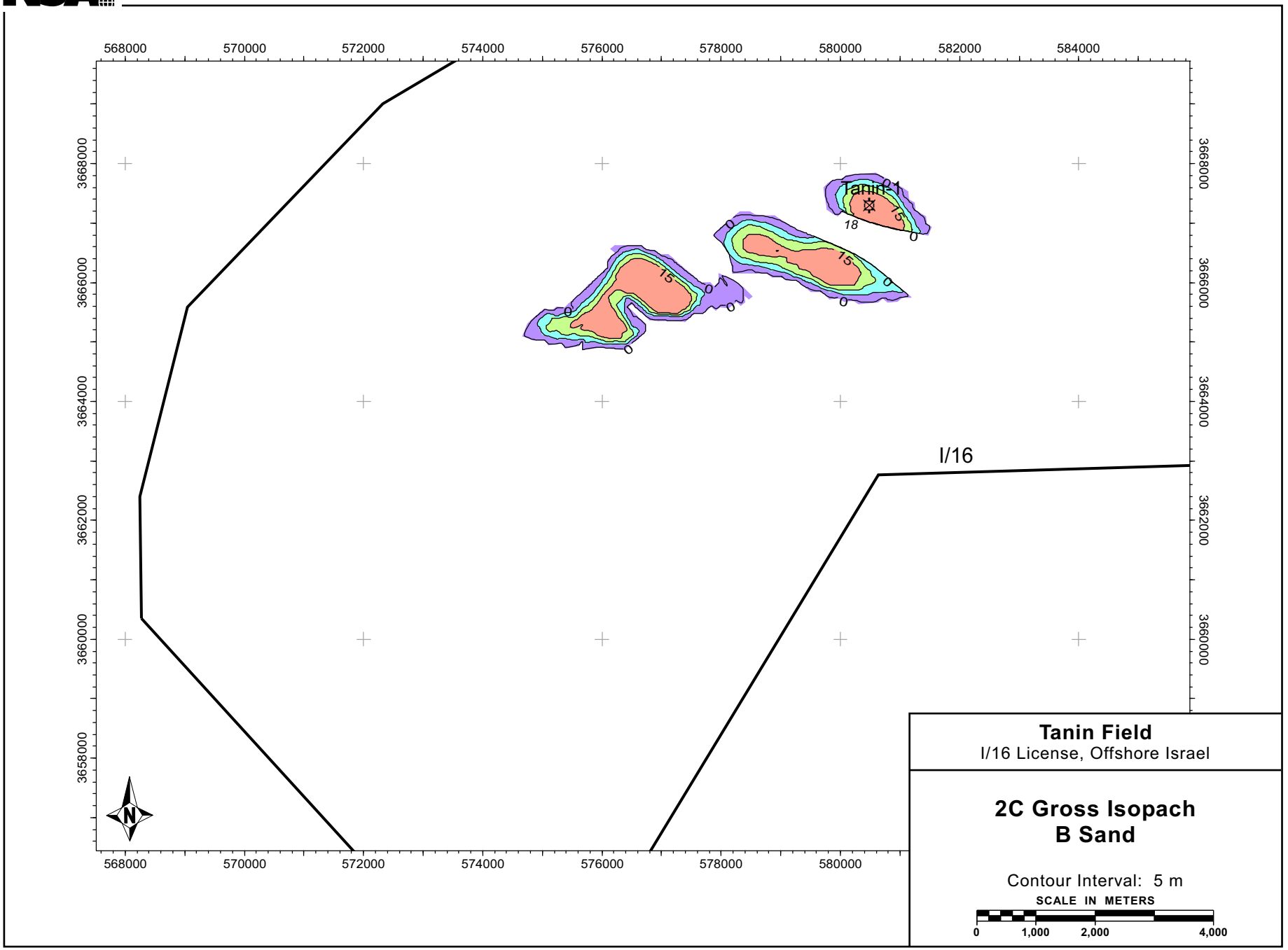


Figure 23

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

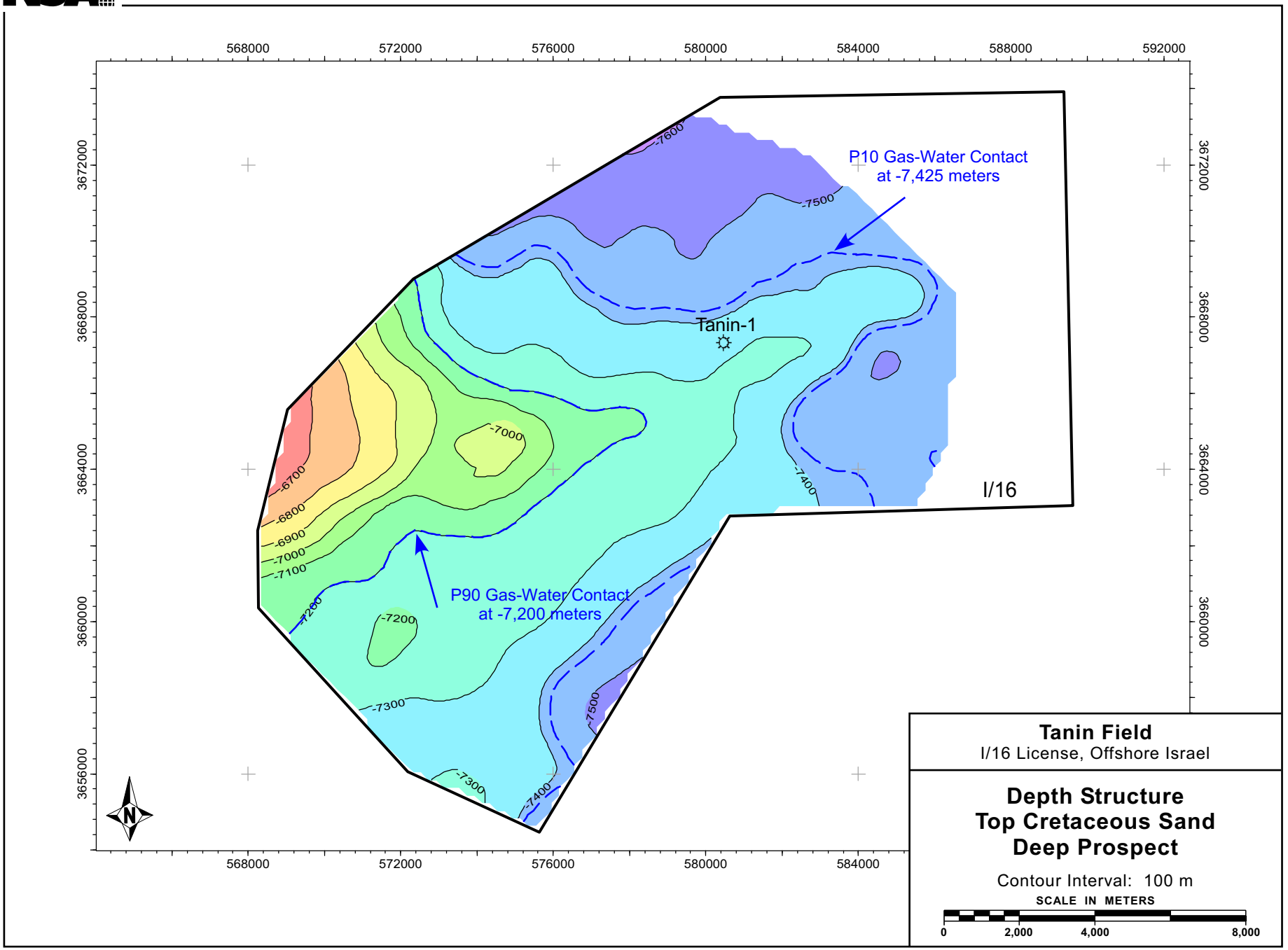


Figure 24

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

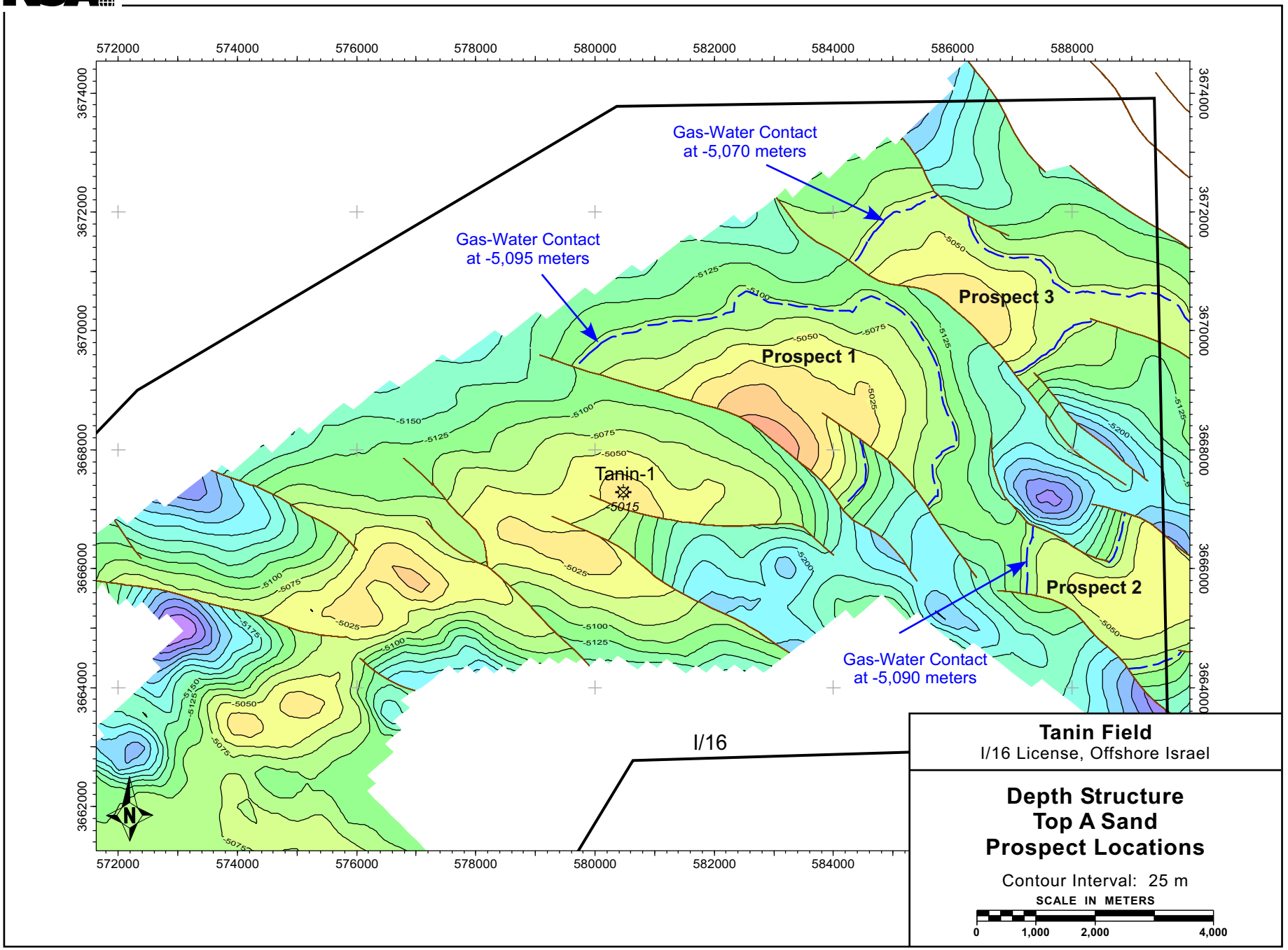


Figure 25

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

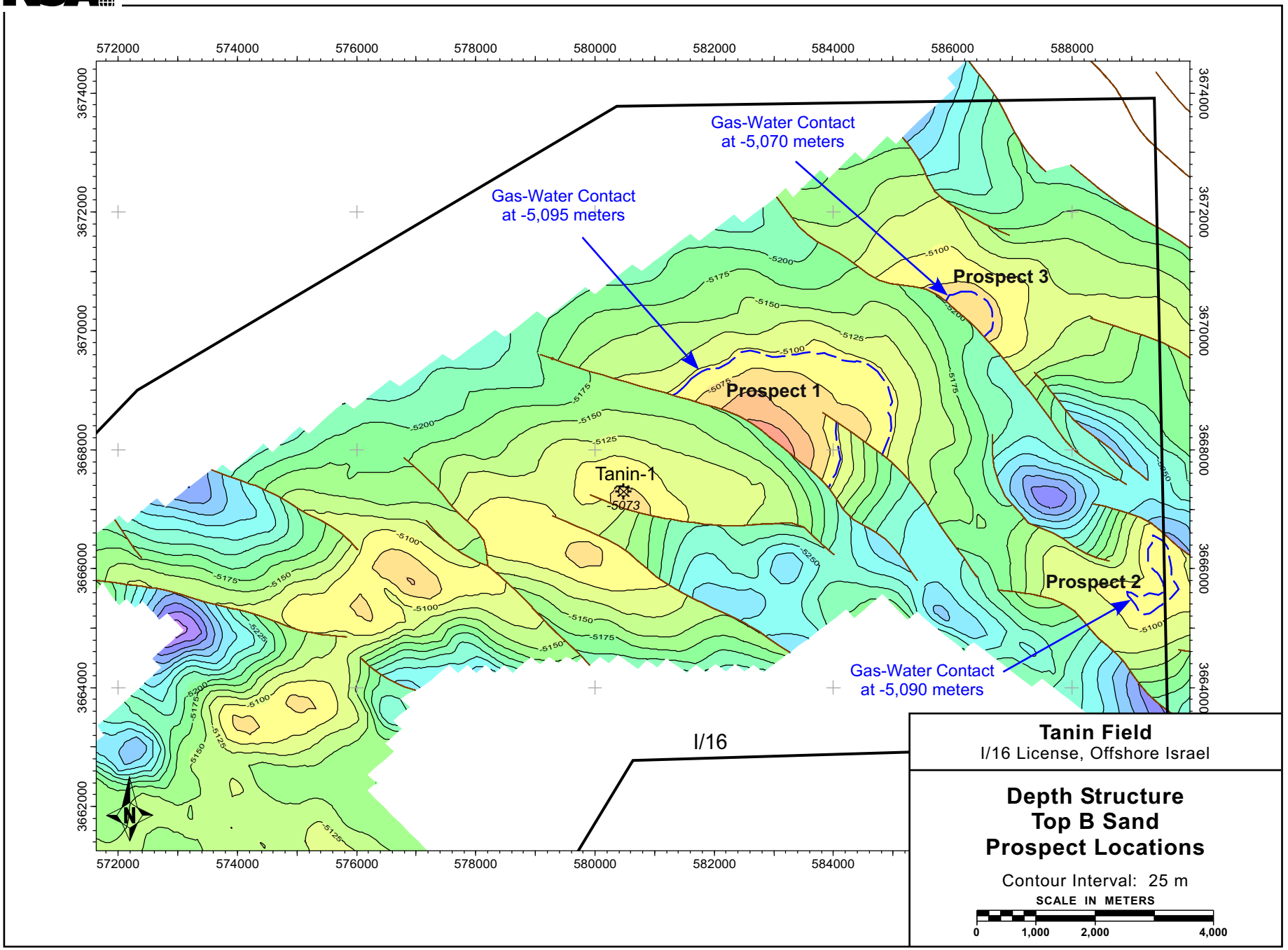


Figure 26

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

APPENDIX – KARISH FIELD STANDALONE DEVELOPMENT SCENARIO

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED LOW ESTIMATE (1C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH FIELD, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	2.4	32.8	4.852	78.36	1,045,347.4	114,322.8	73,039.7	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	2.4	32.8	4.949	79.77	1,065,869.3	116,787.5	73,841.7	0.0	0.0	68,309.3
12-31-2023	181.1	176.6	2.4	32.8	5.048	81.20	1,086,801.6	119,301.6	74,669.8	0.0	0.0	69,675.5
12-31-2024	181.1	176.6	2.4	32.8	5.149	82.66	1,108,152.5	121,866.0	81,792.2	0.0	0.0	71,069.0
12-31-2025	163.0	158.9	2.2	29.6	5.252	84.16	1,016,893.4	111,503.5	75,416.2	21,089.9	0.0	72,239.4
12-31-2026	144.9	141.3	1.9	26.3	5.357	85.68	921,850.1	100,664.4	68,761.4	21,511.7	0.0	73,429.4
12-31-2027	108.7	105.9	1.4	19.7	5.465	87.23	704,926.9	75,770.8	54,084.9	21,941.9	0.0	74,011.6
12-31-2028	54.3	53.0	0.7	9.9	5.574	88.82	359,280.4	35,995.7	20,055.8	0.0	0.0	73,578.3
12-31-2029	17.4	17.0	0.2	3.2	5.685	90.44	117,670.5	8,088.6	4,128.0	0.0	0.0	73,725.8
12-31-2030	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	40,376.1	0.0
SUBTOTAL	1,212.7	1,182.4	16.1	220.0	5.154	82.73	7,426,792.1	804,300.9	566,824.5	1,689,509.7	40,376.1	643,008.3
REMAINING	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	1,212.7	1,182.4	16.1	220.0	5.154	82.73	7,426,792.1	804,300.9	566,824.5	1,689,509.7	40,376.1	643,008.3
CUM PROD	0.0											
ULTIMATE	1,212.7											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	1,105,784.1
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	840,558.1
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	623,170.2
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	477,402.0
12-31-2021	582,456.0	0.0	0.0	582,456.0	23.0	144,689.2	437,766.8	-1,019,675.2	-907,089.0	15.0	296,782.2
12-31-2022	806,930.7	0.0	0.0	806,930.7	23.0	148,235.1	658,695.6	-360,979.6	-484,851.6	20.0	73,416.6
12-31-2023	823,154.7	0.0	0.0	823,154.7	23.0	151,851.8	671,302.9	310,323.3	-93,652.5	25.0	-80,690.5
12-31-2024	833,425.4	22.8	192,657.8	640,767.6	23.0	109,788.0	530,979.6	841,303.0	187,570.6	30.0	-187,439.0
12-31-2025	736,644.4	40.6	303,879.2	432,765.2	23.0	66,423.2	366,342.0	1,207,645.0	363,957.8	35.0	-261,319.9
12-31-2026	657,483.2	46.8	313,189.7	344,293.4	23.0	45,786.7	298,506.7	1,506,151.7	494,617.6	40.0	-312,096.9
12-31-2027	479,117.7	46.8	229,538.5	249,579.3	23.0	23,931.9	225,647.3	1,731,799.0	584,407.1		
12-31-2028	229,650.6	46.8	107,476.5	122,174.1	23.0	0.0	122,174.1	1,853,973.1	628,591.4		
12-31-2029	31,728.1	46.8	14,848.8	16,879.4	23.0	0.0	16,879.4	1,870,852.5	634,140.9		
12-31-2030	0.0	0.0	0.0	0.0	23.0	0.0	0.0	1,870,852.5	634,140.9		
12-31-2031	-40,376.1	0.0	0.0	-40,376.1	23.0	0.0	-40,376.1	1,830,476.4	623,170.2		
SUBTOTAL	3,682,772.8		1,161,590.4	2,521,182.4		690,705.9	1,830,476.4	1,830,476.4	623,170.2		
REMAINING	0.0		0.0	0.0		0.0	0.0	1,830,476.4	623,170.2		
TOTAL	3,682,772.8		1,161,590.4	2,521,182.4		690,705.9	1,830,476.4	1,830,476.4	623,170.2		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

(1) Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
(2) Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED BEST ESTIMATE (2C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH FIELD, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	3.2	33.6	4.852	78.36	1,106,648.9	124,887.8	77,037.4	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	3.2	33.6	4.949	79.77	1,128,271.6	127,490.2	77,879.9	0.0	0.0	68,309.3
12-31-2023	181.1	176.6	3.2	33.6	5.048	81.20	1,150,326.8	130,144.7	78,749.3	0.0	0.0	69,675.5
12-31-2024	181.1	176.6	3.2	33.6	5.149	82.66	1,172,823.1	132,852.2	86,326.0	0.0	0.0	71,069.0
12-31-2025	181.1	176.6	3.2	33.6	5.252	84.16	1,195,769.3	135,613.8	87,393.1	0.0	0.0	72,490.4
12-31-2026	181.1	176.6	3.2	33.6	5.357	85.68	1,219,174.4	138,430.8	88,491.4	0.0	0.0	73,940.2
12-31-2027	163.0	158.9	2.9	30.3	5.465	87.23	1,118,694.4	126,621.8	81,430.9	21,941.9	0.0	75,157.9
12-31-2028	144.9	141.3	2.6	26.9	5.574	88.82	1,014,067.0	114,291.3	63,222.2	22,380.7	0.0	76,396.0
12-31-2029	126.8	123.6	2.2	23.5	5.685	90.44	904,666.0	101,364.3	56,022.6	22,828.4	0.0	77,652.2
12-31-2030	72.4	70.6	1.3	13.5	5.799	92.08	526,976.8	56,713.1	31,102.8	0.0	0.0	77,214.4
12-31-2031	37.0	36.1	0.7	6.9	5.915	93.77	274,550.6	26,790.3	14,389.2	0.0	0.0	77,435.3
SUBTOTAL	1,630.7	1,589.9	28.7	302.8	5.275	84.48	10,811,968.8	1,215,200.3	783,079.6	1,692,117.2	0.0	806,310.3
REMAINING	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	42,007.2	0.0
TOTAL	1,630.7	1,589.9	28.7	302.8	5.275	84.48	10,811,968.8	1,215,200.3	783,079.6	1,692,117.2	42,007.2	806,310.3
CUM PROD	0.0											
ULTIMATE	1,630.7											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	1,796,743.1
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	1,385,967.0
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	1,057,502.1
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	841,645.4
12-31-2021	629,194.7	0.0	0.0	629,194.7	23.0	156,015.6	473,179.1	-984,262.9	-882,118.9	15.0	579,343.1
12-31-2022	854,592.1	0.0	0.0	854,592.1	23.0	159,773.7	694,818.4	-289,444.5	-436,726.1	20.0	263,318.7
12-31-2023	871,757.3	0.0	0.0	871,757.3	23.0	163,606.9	708,150.4	418,706.0	-24,054.3	25.0	50,912.7
12-31-2024	882,575.8	29.5	263,727.0	618,848.8	23.0	105,323.1	513,525.7	932,231.6	247,924.7	30.0	-93,578.6
12-31-2025	900,271.9	44.5	406,149.4	494,122.5	23.0	76,521.3	417,601.2	1,349,832.8	448,992.3	35.0	-192,565.5
12-31-2026	918,312.0	46.8	435,315.0	482,997.0	23.0	73,847.6	409,149.4	1,758,982.2	628,081.6	40.0	-260,476.9
12-31-2027	813,541.9	46.8	386,049.0	427,492.9	23.0	65,676.2	361,816.7	2,120,798.9	772,055.5		
12-31-2028	737,776.8	46.8	345,279.5	392,497.2	23.0	54,770.1	337,727.2	2,458,526.1	894,194.7		
12-31-2029	646,798.5	46.8	302,701.7	344,096.8	23.0	43,383.2	300,713.6	2,759,239.7	993,061.3		
12-31-2030	361,946.5	46.8	169,391.0	192,555.5	23.0	3,780.1	188,775.4	2,948,015.1	1,049,483.3		
12-31-2031	155,935.8	46.8	72,978.0	82,957.9	23.0	18,738.5	64,219.4	3,012,234.5	1,066,932.6		
SUBTOTAL	6,315,261.4		2,381,590.6	3,933,670.8		921,436.3	3,012,234.5	3,012,234.5	1,066,932.6		
REMAINING	-42,007.2		0.0	-42,007.2		0.0	-42,007.2	2,970,227.3	1,057,502.1		
TOTAL	6,273,254.2		2,381,590.6	3,891,663.6		921,436.3	2,970,227.3	2,970,227.3	1,057,502.1		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
[2] Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESOURCES AND CASH FLOW
UNRISKED HIGH ESTIMATE (3C) CONTINGENT RESOURCES
ENERGEAN ISRAEL LTD INTEREST
KARISH FIELD, OFFSHORE ISRAEL
AS OF OCTOBER 31, 2017

Period Ending	Gross Gas Resources BCF	Net Resources Gas[1] BCF	Net Resources Liquids MMBBL	Net Resources Equivalent MMBOE	Average Prices Gas $/MCF	Average Prices Liquids $/BBL	Gross Revenue M$	State Royalties M$	Payments to Seller M$	Net Capital Cost M$	Net Abdnmnt Cost M$	Net Operating Expense M$
12-31-2017	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	10,850.0	291,007.6	0.0	0.0
12-31-2019	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	15,341.9	448,543.2	0.0	0.0
12-31-2020	0.0	0.0	0.0	0.0	0.000	0.00	0.0	0.0	14,842.8	676,856.5	0.0	0.0
12-31-2021	181.1	176.6	3.9	34.3	4.852	78.36	1,162,841.9	133,790.4	80,782.5	208,559.0	0.0	66,969.9
12-31-2022	181.1	176.6	3.9	34.3	4.949	79.77	1,185,473.7	136,518.9	81,672.1	0.0	0.0	68,309.3
12-31-2023	181.1	176.6	3.9	34.3	5.048	81.20	1,208,558.2	139,302.0	89,513.8	0.0	0.0	69,675.5
12-31-2024	181.1	176.6	3.9	34.3	5.149	82.66	1,232,104.4	142,140.7	90,603.9	0.0	0.0	71,069.0
12-31-2025	181.1	176.6	3.9	34.3	5.252	84.16	1,256,121.5	145,036.3	91,725.9	0.0	0.0	72,490.4
12-31-2026	181.1	176.6	3.9	34.3	5.357	85.68	1,280,618.9	147,989.7	92,880.2	0.0	0.0	73,940.2
12-31-2027	181.1	176.6	3.9	34.3	5.465	87.23	1,305,606.3	151,002.2	94,067.6	0.0	0.0	75,419.0
12-31-2028	181.1	176.6	3.9	34.3	5.574	88.82	1,331,093.4	154,075.0	84,438.8	0.0	0.0	76,927.4
12-31-2029	181.1	176.6	3.9	34.3	5.685	90.44	1,357,090.3	157,209.2	86,193.4	0.0	0.0	78,466.0
12-31-2030	163.0	158.9	3.5	30.9	5.799	92.08	1,245,192.4	143,779.5	78,798.8	23,284.9	0.0	79,758.2
12-31-2031	144.9	141.3	3.1	27.5	5.915	93.77	1,128,688.5	129,771.2	71,077.6	23,750.6	0.0	81,072.0
SUBTOTAL	1,937.7	1,889.3	41.8	367.5	5.354	85.63	13,693,389.3	1,580,615.2	982,789.3	1,672,001.8	0.0	814,097.0
REMAINING	161.1	157.1	3.5	30.6	6.099	96.43	1,293,327.5	137,573.6	74,133.5	24,225.6	44,578.4	243,613.7
TOTAL	2,098.9	2,046.4	45.3	398.1	5.411	86.46	14,986,716.8	1,718,188.8	1,056,922.8	1,696,227.4	44,578.4	1,057,710.7
CUM PROD	0.0											
ULTIMATE	2,098.9											

Period Ending	Cash Flow Before Levy and Corporate Income Taxes M$	Effective Levy Rate[2] %	Levy[2] M$	Cash Flow After Levy and Before Corporate Income Taxes M$	Corporate Income Tax Rate[2] %	Corporate Income Taxes[2] M$	Future Net Cash Flow After Levy and Corporate Income Taxes Undiscounted Period M$	Undiscounted Cum M$	Disc at 10% Cum M$	Present Worth Profile Disc Rate %	Present Worth Profile Cum PW M$
12-31-2017	0.0	0.0	0.0	0.0	24.0	0.0	0.0	0.0	0.0	5.0	2,500,391.3
12-31-2018	-301,857.6	0.0	0.0	-301,857.6	23.0	0.0	-301,857.6	-301,857.6	-283,372.8	7.5	1,917,845.9
12-31-2019	-463,885.1	0.0	0.0	-463,885.1	23.0	0.0	-463,885.1	-765,742.6	-679,262.1	10.0	1,464,091.7
12-31-2020	-691,699.3	0.0	0.0	-691,699.3	23.0	0.0	-691,699.3	-1,457,441.9	-1,215,768.2	12.0	1,172,255.7
12-31-2021	672,740.0	0.0	0.0	672,740.0	23.0	166,404.2	506,335.9	-951,106.1	-858,739.3	15.0	824,985.4
12-31-2022	898,973.4	0.0	0.0	898,973.4	23.0	170,354.5	728,618.9	-222,487.1	-391,679.7	20.0	418,325.4
12-31-2023	910,066.9	3.5	32,487.6	877,579.3	23.0	165,319.0	712,260.2	489,773.1	23,387.1	25.0	152,937.0
12-31-2024	928,290.6	32.5	305,585.2	622,705.4	23.0	106,583.3	516,122.2	1,005,895.3	296,741.3	30.0	-23,669.4
12-31-2025	946,868.9	46.0	440,924.2	505,944.7	23.0	79,613.5	426,331.2	1,432,226.4	502,012.2	35.0	-142,820.4
12-31-2026	965,808.8	46.8	457,543.5	508,265.3	23.0	80,032.4	428,232.9	1,860,459.3	689,454.6	40.0	-223,832.2
12-31-2027	985,117.4	46.8	466,346.3	518,771.1	23.0	82,334.0	436,437.1	2,296,896.4	863,121.4		
12-31-2028	1,015,652.3	46.8	475,325.3	540,327.0	23.0	84,681.6	455,645.5	2,752,541.8	1,027,905.8		
12-31-2029	1,035,221.7	46.8	484,483.8	550,738.0	23.0	87,076.1	463,661.9	3,216,203.7	1,180,345.4		
12-31-2030	919,571.0	46.8	430,359.2	489,211.8	23.0	77,875.0	411,336.8	3,627,540.5	1,303,287.6		
12-31-2031	823,017.0	46.8	385,172.0	437,845.0	23.0	105,127.3	332,717.7	3,960,258.2	1,393,691.5		
SUBTOTAL	8,643,886.1		3,478,227.0	5,165,659.0		1,205,400.8	3,960,258.2	3,960,258.2	1,393,691.5		
REMAINING	769,202.7		380,849.6	388,353.1		103,989.9	284,363.2	4,244,621.5	1,464,091.7		
TOTAL	9,413,088.8		3,859,076.6	5,554,012.2		1,309,390.7	4,244,621.5	4,244,621.5	1,464,091.7		

Note: Totals may not add because of rounding. Liquids contain condensate and natural gas liquids.

[1] Unrisked net contingent gas resources are after a 2.5 percent shrinkage for processing, fuel, and flare.
[2] Levy and corporate income tax rates and amounts were provided by Energean Israel Ltd.

BASED ON ESCALATED PRICE AND COST PARAMETERS

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ESTIMATES

of

GROSS (100 PERCENT) RESERVES AND FUTURE REVENUE, CONTINGENT RESOURCES, AND PROSPECTIVE RESOURCES

for

CERTAIN OIL AND GAS PROPERTIES

located in the

PRINOS BASIN, OFFSHORE GREECE

as of

OCTOBER 31, 2017

Prepared for and

BASED ON PRICE AND COST PARAMETERS

specified by

ENERGEAN OIL & GAS SA

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

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January 26, 2018

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21 Gloucester Place
London W1U 8HR
United Kingdom

Energean Oil & Gas SA
32, Kifissias Avenue, Atrina Center, 17th Floor
151 25 Marousi
Athens, Greece

Ladies and Gentlemen:

In accordance with your request, we have estimated the gross (100 percent) proved, probable, and possible reserves and future revenue, as of October 31, 2017, for certain oil and gas properties located in the Prinos Basin, offshore Greece. Also as requested, we have estimated the gross (100 percent) contingent and prospective resources, as of October 31, 2017, for certain oil and gas properties located in the Prinos Basin, offshore Greece. Energean Oil & Gas SA (Energean) owns 100 percent interest in these properties. We completed our evaluation on or about December 20, 2017. This report has been prepared using price and cost parameters specified by Energean, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification; tables that set forth our estimates of reserves, contingent resources, and prospective resources, by category, for each asset; and a list of abbreviations used in this report. This report has been prepared for use by Energean Oil & Gas PLC in filing with the London Stock Exchange; in our opinion the assumptions, data, methods, and procedures used in preparation of this report are appropriate for such purpose.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) reserves and future net revenue for the Prinos Basin properties, as of October 31, 2017, to be:

	Gross (100%) Reserves		Future Net Revenue After Corporate Income Tax[1] (MM$)	
Category	Oil (MMBBL)	Sales Gas (BCF)	Total	Present Worth at 10%
Proved Developed	3.9	0.0	(436.3)[2]	(158.3)[2]
Proved Undeveloped	24.1	3.1	1,194.4	596.3
Proved (1P)	28.0	3.1	758.2	438.1

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Category	Gross (100%) Reserves Oil (MMBBL)	Gross (100%) Reserves Sales Gas (BCF)	Future Net Revenue After Corporate Income Tax[1] (MM$) Total	Future Net Revenue After Corporate Income Tax[1] (MM$) Present Worth at 10%
Probable	11.5	2.9	546.1	292.6
Proved + Probable (2P)	39.5	6.0	1,304.3	730.7
Possible	12.0	3.0	632.7	280.6
Proved + Probable + Possible (3P)	51.5	9.0	1,937.0	1,011.2

Totals may not add because of rounding.

(1) Approximately 1 percent of the gross revenue, prior to any deductions, is from sulfur sales.
(2) Future net revenue is negative because the proved developed category includes all proved operating costs.

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Proved developed reserves are inclusive of proved developed producing and proved developed non-producing reserves. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves shown in this report is the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for capital costs, abandonment costs, operating expenses, royalties owed to the Greek government, and corporate income taxes. It is our understanding that Energean has a $319 million tax loss carryforward, which is accounted for in our estimates of future net revenue. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using oil and gas price parameters specified by Energean. Oil prices are based on October 31, 2017, Dated Brent prices and are adjusted for quality, transportation fees, and market differentials. The gas price used in this report is $7.302 per MCF, which is the average price paid by Energean for fuel gas for these properties from October 2016 through September 2017 adjusted for energy content, transportation fees, and market differentials. The sulfur price used in this report is $61.80 per metric ton, which is a contractual price adjusted by a transportation fee. All prices are escalated 2 percent on January 1 of each year throughout the lives of the properties. Oil prices before adjustments, both before and after escalation, are shown in the following table:

Period Ending	Base Oil Price ($/Barrel)	Escalated Oil Price ($/Barrel)
12-31-2017	60.00	60.00
12-31-2018	62.50	63.75
12-31-2019	65.00	67.63
Thereafter	65.00	Escalated 2 percent on January 1 of each year.

Operating costs used in this report are based on operating expense records and budgets of Energean, the operator of the properties, and include only direct lease-level and field-level costs. As requested, headquarters general and administrative overhead expenses of Energean are not included. Also as requested, operating costs are escalated 2 percent on January 1 of each year throughout the lives of the properties.

Capital costs used in this report were provided by Energean and are based on budgeted expenditures and authorizations for expenditure. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Energean's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Energean plans to sell the drilling rig that is currently operating in the Prinos Basin at the end of the drilling campaign; the company estimates that it will receive $10 million from the sale. The proceeds from the drilling rig sale are not included in our estimates of future net revenue. As requested, capital costs and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report are subclassified as development unclarified. The contingent resources shown in this report for Epsilon and Prinos North Fields and A, B, and C Reservoirs in Prinos Field are contingent upon improved economic parameters and improved recovery rates. The contingent resources shown in this report for Athos, Delta, and Kazaviti Discoveries and D Reservoir in Prinos Field are contingent upon creation of a development plan and commitment from Energean to develop the properties. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. We did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the unrisked gross (100 percent) contingent resources for the Prinos Basin properties, as of October 31, 2017, to be:

	Unrisked Gross (100%) Contingent Resources[1]	
Category	Oil (MMBBL)	Sales Gas (BCF)
Low Estimate (1C)	6.5	1.0
Best Estimate (2C)	22.9	5.3
High Estimate (3C)	44.3	10.8

[1] Unrisked gross (100 percent) contingent resources are the arithmetic sum of multiple probability distributions.

The oil volumes shown include crude oil only.

The contingent resources shown in this report have been estimated using probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk. As recommended in the PRMS, the 1C, 2C, and 3C contingent resources have been aggregated beyond the field level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. The B and C Reservoirs located in a separate structure located in the southeast extension of Prinos Field have been subclassified as a prospect, and the prospect is referred to as Prinos SE Ext Prospect. The undiscovered accumulation named "Alpha" has been subclassified as a lead. The 2007 PRMS defines a prospect as a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target, a lead as a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be subclassified as a prospect, and a play as a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A geologic risk assessment was performed for these exploration opportunities, as discussed in subsequent paragraphs. Because of the early stage of development of these exploration opportunities, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

Totals of unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each exploration opportunity, meaningful totals beyond these levels can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked and risked gross (100 percent) prospective oil resources for the Prinos Basin exploration opportunities, as of October 31, 2017, to be:

	Gross (100%) Prospective Oil Resources[1] (MMBBL)	
Category	Unrisked	Risked
Low Estimate	6.3	1.1
Best Estimate	8.9	1.6
High Estimate	12.4	2.2

[1] Gross (100 percent) prospective oil resources are the arithmetic sum of multiple probability distributions.

The oil volumes shown include crude oil only.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. As recommended in the PRMS, the low, best, and high estimate prospective resources have been aggregated beyond the prospect and lead levels by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. The estimates for risked resources are derived directly from the estimates for unrisked resources, incorporating geologic risk assessments for the exploration opportunities; such risked resources do not incorporate a development risk assessment. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and

preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each play type.

Each exploration opportunity was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume discoveries may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of the exploration opportunities.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes summary projections of reserves and revenue by reserves category. Also included are an Executive Summary and technical discussions with pertinent figures for each asset.

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves, contingent resources, and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Energean, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. The contingent and prospective resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there

are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energean and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Philip S. (Scott) Frost
By:
Philip S. (Scott) Frost, P.E. 88738
Senior Vice President

Date Signed: January 26, 2018

/s/ Michelle F. Herrera
By:
Michelle F. Herrera, P.G. 11912
Geoscientist

Date Signed: January 26, 2018

PSF:DSS

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

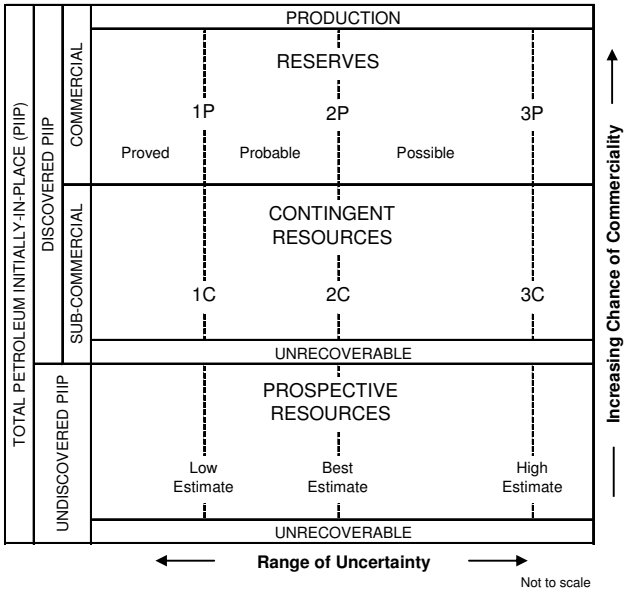


Figure 1-1: Resources Classification Framework.

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

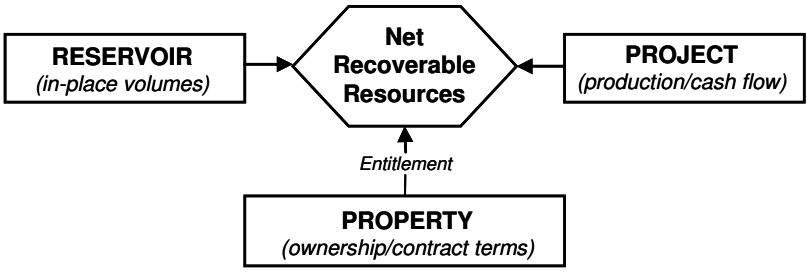


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	**Definition**	**Guidelines**
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	**Definition**	**Guidelines**
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Philip S. (Scott) Frost, Licensed Professional Engineer, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Energean Oil & Gas SA. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas SA or its affiliated companies.

I attended Tulane University, and I graduated in 1984 with a Master's Degree in Business Administration; I attended Vanderbilt University, and I graduated in 1979 with a Bachelor of Engineering Degree in Mechanical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 36 years of experience in petroleum engineering studies and evaluations.

/s/ Philip S. (Scott) Frost

By: _____

Philip S. (Scott) Frost, P.E.
Senior Vice President
Texas Registration No. 88738

January 26, 2018
Dallas, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Michelle F. Herrera, Licensed Professional Geoscientist, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Energean Oil & Gas SA. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas SA or its affiliated companies.

I attended University of Texas at Dallas, I graduated in 2002 with a Bachelor of Science Degree in Geoscience; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 15 years of experience in geological and geophysical studies and evaluations.

/s/ Michelle F. Herrera
By: _____
Michelle F. Herrera, P.G.
Geoscientist
Texas Registration No. 11912

January 26, 2018
Dallas, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF GROSS (100 PERCENT) RESERVES
PRINOS BASIN, OFFSHORE GREECE
ENERGEAN OIL & GAS SA
AS OF OCTOBER 31, 2017

Field/Category	Gross (100%) Reserves[1] Oil (MMBBL)	Gross (100%) Reserves[1] Sales Gas (BCF)
Prinos Field, A, B, and C Reservoirs		
Proved Developed	3.8	0.0
Proved Undeveloped	9.0	1.5
Proved (1P)	12.8	1.5
Probable	5.1	1.4
Proved + Probable (2P)	17.8	2.9
Possible	7.3	1.8
Proved + Probable + Possible (3P)	25.2	4.8
Epsilon Field		
Proved Undeveloped	13.0	1.4
Proved (1P)	13.0	1.4
Probable	5.4	1.3
Proved + Probable (2P)	18.4	2.8
Possible	3.5	1.0
Proved + Probable + Possible (3P)	21.9	3.8
Prinos North Field		
Proved Developed	0.1	0.0
Proved Undeveloped	2.1	0.1
Proved (1P)	2.2	0.1
Probable	1.1	0.1
Proved + Probable (2P)	3.3	0.3
Possible	1.1	0.1
Proved + Probable + Possible (3P)	4.4	0.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF GROSS (100 PERCENT) RESERVES
PRINOS BASIN, OFFSHORE GREECE
ENERGEAN OIL & GAS SA
AS OF OCTOBER 31, 2017

Field/Category	Gross (100%) Reserves[1] Oil (MMBBL)	Gross (100%) Reserves[1] Sales Gas (BCF)
Total		
Proved Developed	3.9	0.0
Proved Undeveloped	24.1	3.1
Proved (1P)	28.0	3.1
Probable	11.5	2.9
Proved + Probable (2P)	39.5	6.0
Possible	12.0	3.0
Proved + Probable + Possible (3P)	51.5	9.0

Totals may not add because of rounding.

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

(1) Technically recoverable volumes that are economic are classified as reserves; the remaining volumes are classified as development unclarified contingent resources.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF UNRISKED GROSS (100 PERCENT)
DEVELOPMENT UNCLARIFIED CONTINGENT RESOURCES
PRINOS BASIN, OFFSHORE GREECE
ENERGEAN OIL & GAS SA
AS OF OCTOBER 31, 2017

Discovery or Field/Category	Unrisked Gross (100%) Contingent Resources Oil (MMBBL)	Sales Gas (BCF)
Athos Discovery		
Low Estimate (1C)	1.6	0.0
Best Estimate (2C)	2.4	0.0
High Estimate (3C)	3.5	0.0
Delta Discovery		
Low Estimate (1C)	0.7	0.0
Best Estimate (2C)	1.6	0.0
High Estimate (3C)	2.8	0.0
Epsilon Field[(1)]		
Low Estimate (1C)	0.0	0.0
Best Estimate (2C)	0.1	0.0
High Estimate (3C)	3.7	1.1
Kazaviti Discovery		
Low Estimate (1C)	0.4	0.0
Best Estimate (2C)	0.9	0.0
High Estimate (3C)	1.2	0.0
Prinos Field, A, B, and C Reservoirs[(1)]		
Low Estimate (1C)	2.7	0.9
Best Estimate (2C)	15.6	4.9
High Estimate (3C)	29.1	9.2
Prinos Field, D Reservoir		
Low Estimate (1C)	0.0	0.0
Best Estimate (2C)	0.0	0.0
High Estimate (3C)	0.1	0.0

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF UNRISKED GROSS (100 PERCENT)
DEVELOPMENT UNCLARIFIED CONTINGENT RESOURCES
PRINOS BASIN, OFFSHORE GREECE
ENERGEAN OIL & GAS SA
AS OF OCTOBER 31, 2017

Discovery or Field/Category	Unrisked Gross (100%) Contingent Resources Oil (MMBBL)	Sales Gas (BCF)
Prinos North Field[1]		
Low Estimate (1C)	1.1	0.2
Best Estimate (2C)	2.4	0.4
High Estimate (3C)	3.8	0.6
Total[2]		
Low Estimate (1C)	6.5	1.0
Best Estimate (2C)	22.9	5.3
High Estimate (3C)	44.3	10.8

Totals may not add because of rounding.

(1) Technically recoverable volumes that are economic are classified as reserves; the remaining volumes are classified as development unclarified contingent resources.

(2) Totals are the arithmetic sum of multiple asset-level probability distributions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF GROSS (100 PERCENT) PROSPECTIVE OIL RESOURCES
PRINOS BASIN, OFFSHORE GREECE
ENERGEAN OIL & GAS SA
AS OF OCTOBER 31, 2017

Prospect or Lead/Category	Gross (100%) Prospective Oil Resources	
	Unrisked[1] (MMBBL)	Risked (MMBBL)
Alpha Lead		
Low Estimate	4.6	0.7
Best Estimate	6.3	1.0
High Estimate	8.6	1.4
Prinos SE Ext Prospect, B and C Reservoirs		
Low Estimate	1.8	0.4
Best Estimate	2.6	0.6
High Estimate	3.7	0.8
Total[2]		
Low Estimate	6.3	1.1
Best Estimate	8.9	1.6
High Estimate	12.4	2.2

Totals may not add because of rounding.

(1) Totals of unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each property, meaningful totals beyond these levels can be defined only by summing risked prospective resources. Such risk is often significant.

(2) Totals are the arithmetic sum of multiple asset-level probability distributions.

ABBREVIATIONS

$	United States dollars
°	degrees
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
A	Alpha
AFE	authorization for expenditure
API	American Petroleum Institute
Avg	average
B	Beta
BCF	billions of cubic feet
BOPD	barrels of oil per day
C	Charlie
CO_2	carbon dioxide
cp	centipoise
CPI	computer-processed interpretation
DCA	decline curve analysis
DST	drillstem test
Energean	Energean Oil & Gas SA
EUR	estimated ultimate recovery
FVF	formation volume factor
FWHP	flowing wellhead pressure
GOR	gas-oil ratio
GRV	gross rock volume
H_2S	hydrogen sulfide
hr	hours
in	inches
Kavala	Kavala Oil SA
km	kilometers
LKO	lowest known oil
m	meters
Max	maximum
MBBL	thousands of barrels
MCF	thousands of cubic feet
MD	measured depth
MDT	modular dynamics test
MM$	millions of United States dollars

ABBREVIATIONS

MMBBL	millions of barrels
NSAI	Netherland, Sewell & Associates, Inc.
NSV	net sand volume
NTG	net-to-gross ratio
OOIP	original oil-in-place
OWC	oil-water contact
P05	5 percent confidence level
P10	10 percent confidence level
P50	50 percent confidence level
P90	90 percent confidence level
P95	95 percent confidence level
P99	99 percent confidence level
P_g	probability of geologic success
ppm	parts per million
Prinos SE Ext Prospect	Prinos Southeast Extension Prospect
PRMS	Petroleum Resources Management System
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure-volume-temperature
RB/STB	reservoir barrels per stock tank barrel
Regal	Regal Petroleum PLC
RFT	repeat formation test
SCF/STB	standard cubic feet per stock tank barrel
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
S_w	water saturation
TPG	Top Prinos Group
TVDSS	true vertical depth subsea
V_{sh}	shale volume
XPT	express pressure test

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROVED DEVELOPED RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	3,088	0.2	0.0	10.1	12.2	0.0	6.3	0.1	0.0	(8.4)	(8.4)
12-31-2018	2,562	0.9	0.0	53.5	8.2	0.0	26.4	0.0	0.0	18.9	9.4
12-31-2019	1,937	0.7	0.0	43.2	6.2	0.0	29.1	0.0	0.0	7.9	16.1
12-31-2020	1,419	0.5	0.0	32.4	5.8	0.0	31.4	0.0	0.0	(4.8)	12.3
12-31-2021	1,055	0.4	0.0	24.6	6.0	0.0	33.0	0.0	0.0	(14.3)	2.3
12-31-2022	768	0.3	0.0	18.4	6.1	0.0	34.0	0.0	0.0	(21.8)	(11.7)
12-31-2023	575	0.2	0.0	14.0	6.2	0.0	35.0	0.0	0.0	(27.2)	(27.5)
12-31-2024	436	0.2	0.0	10.9	6.3	0.0	35.2	0.0	0.0	(30.6)	(43.7)
12-31-2025	335	0.1	0.0	8.5	4.7	0.0	35.3	0.0	0.0	(31.4)	(58.8)
12-31-2026	258	0.1	0.0	6.7	4.8	0.0	35.3	0.0	0.0	(33.3)	(73.4)
12-31-2027	202	0.1	0.0	5.4	4.9	0.0	35.3	0.0	0.0	(34.8)	(87.3)
12-31-2028	158	0.1	0.0	4.3	5.0	0.0	35.2	0.0	0.0	(35.9)	(100.3)
12-31-2029	124	0.0	0.0	3.5	5.1	0.0	35.2	0.0	0.0	(36.8)	(112.4)
12-31-2030	99	0.0	0.0	2.8	5.2	0.0	35.0	0.0	0.0	(37.4)	(123.6)
12-31-2031	79	0.0	0.0	2.3	4.0	0.0	34.9	0.0	0.0	(36.6)	(133.5)
12-31-2032	63	0.0	0.0	1.9	4.0	0.0	34.7	0.0	0.0	(36.9)	(142.6)
12-31-2033	50	0.0	0.0	1.5	4.1	0.0	34.5	0.0	0.0	(37.2)	(151.0)
12-31-2034	0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	(35.7)	(158.3)
12-31-2035											
12-31-2036											
TOTAL		3.9	0.0	244.0	98.7	35.7	545.8	0.1	0.0	(436.3)	(158.3)
CUM PROD		114.8	0.0								
ULTIMATE		118.7	0.0								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE	
FOR 8 PCT, PRESENT WORTH MM$	(191.0)
FOR 15 PCT, PRESENT WORTH MM$	(101.6)
FOR 20 PCT, PRESENT WORTH MM$	(67.3)
FOR 25 PCT, PRESENT WORTH MM$	(45.7)
FOR 30 PCT, PRESENT WORTH MM$	(31.5)

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROVED UNDEVELOPED RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	OIL (MMBBL)	SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE[2] (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	1,441	0.5	0.0	29.5	124.9	0.0	(1.2)	0.9	0.0	(95.2)	(89.3)
12-31-2019	6,250	2.3	0.5	143.8	92.8	0.0	(1.6)	5.9	0.0	46.7	(49.5)
12-31-2020	7,884	2.9	0.7	186.4	52.8	0.0	(1.9)	7.6	0.0	127.8	49.7
12-31-2021	8,547	3.1	0.7	205.2	43.1	0.0	(2.4)	8.1	0.0	156.4	160.0
12-31-2022	7,749	2.8	0.6	189.7	0.0	0.0	(2.9)	6.8	20.1	165.7	266.2
12-31-2023	6,158	2.2	0.4	154.0	0.0	0.0	(3.3)	4.4	31.4	121.5	337.0
12-31-2024	5,176	1.9	0.2	132.2	0.0	0.0	(3.6)	2.8	25.6	107.4	393.8
12-31-2025	4,232	1.5	0.1	110.0	0.0	0.0	(3.8)	1.6	20.2	92.0	438.1
12-31-2026	3,175	1.2	0.0	83.7	0.0	0.0	(3.5)	0.7	13.3	73.2	470.2
12-31-2027	2,880	1.1	0.0	77.8	0.0	0.0	(3.2)	0.5	11.4	69.1	497.7
12-31-2028	2,684	1.0	0.0	74.2	0.0	0.0	(2.9)	0.3	10.2	66.6	521.8
12-31-2029	2,542	0.9	0.0	71.9	0.0	0.0	(2.8)	0.1	9.4	65.1	543.2
12-31-2030	2,410	0.9	0.0	69.8	0.0	0.0	(2.7)	0.0	8.7	63.6	562.2
12-31-2031	2,030	0.7	0.0	60.0	0.0	0.0	(2.0)	0.0	6.4	55.7	577.4
12-31-2032	1,704	0.6	0.0	51.5	0.0	0.0	(1.4)	0.0	4.0	48.9	589.5
12-31-2033	1,242	0.5	0.0	38.3	0.0	0.0	(0.5)	0.0	0.4	38.4	598.1
12-31-2034	0	0.0	0.0	0.0	0.0	8.6	0.0	0.0	0.0	(8.6)	596.3
12-31-2035											
12-31-2036											
TOTAL		24.1	3.1	1,677.9	313.6	8.6	(39.6)	39.7	161.2	1,194.4	596.3
CUM PROD		0.3	0.0								
ULTIMATE		24.5	3.1								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

[2] NEGATIVE OPERATING EXPENSES ARE DUE TO LOWER FUEL GAS PURCHASES IN THE PROVED UNDEVELOPED CASE.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	676.9
FOR 15 PCT, PRESENT WORTH MM$	443.5
FOR 20 PCT, PRESENT WORTH MM$	337.9
FOR 25 PCT, PRESENT WORTH MM$	262.2
FOR 30 PCT, PRESENT WORTH MM$	206.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROVED (1P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	OIL (MMBBL)	SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	3,088	0.2	0.0	10.1	12.2	0.0	6.3	0.1	0.0	(8.4)	(8.4)
12-31-2018	4,003	1.5	0.0	83.0	133.1	0.0	25.2	0.9	0.0	(76.3)	(80.0)
12-31-2019	8,187	3.0	0.5	187.0	99.0	0.0	27.5	5.9	0.0	54.6	(33.4)
12-31-2020	9,302	3.4	0.7	218.8	58.7	0.0	29.5	7.6	0.0	123.0	62.0
12-31-2021	9,602	3.5	0.7	229.8	49.0	0.0	30.5	8.1	0.0	142.2	162.2
12-31-2022	8,517	3.1	0.6	208.0	6.1	0.0	31.1	6.8	20.1	144.0	254.5
12-31-2023	6,733	2.5	0.4	168.0	6.2	0.0	31.7	4.4	31.4	94.3	309.5
12-31-2024	5,612	2.0	0.2	143.1	6.3	0.0	31.6	2.8	25.6	76.8	350.1
12-31-2025	4,567	1.7	0.1	118.5	4.7	0.0	31.5	1.6	20.2	60.6	379.3
12-31-2026	3,433	1.3	0.0	90.5	4.8	0.0	31.8	0.7	13.3	39.9	396.8
12-31-2027	3,082	1.1	0.0	83.2	4.9	0.0	32.1	0.5	11.4	34.3	410.4
12-31-2028	2,842	1.0	0.0	78.5	5.0	0.0	32.3	0.3	10.2	30.7	421.5
12-31-2029	2,666	1.0	0.0	75.4	5.1	0.0	32.4	0.1	9.4	28.3	430.8
12-31-2030	2,509	0.9	0.0	72.6	5.2	0.0	32.4	0.0	8.7	26.2	438.7
12-31-2031	2,109	0.8	0.0	62.3	4.0	0.0	32.9	0.0	6.4	19.1	443.9
12-31-2032	1,767	0.6	0.0	53.3	4.0	0.0	33.3	0.0	4.0	12.0	446.8
12-31-2033	1,292	0.5	0.0	39.8	4.1	0.0	34.0	0.0	0.4	1.2	447.1
12-31-2034	0	0.0	0.0	0.0	0.0	44.3	0.0	0.0	0.0	(44.3)	438.1
12-31-2035											
12-31-2036											
TOTAL		28.0	3.1	1,921.9	412.3	44.3	506.1	39.8	161.2	758.2	438.1
CUM PROD		115.1	0.0								
ULTIMATE		143.1	3.1								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	485.9
FOR 15 PCT, PRESENT WORTH MM$	341.9
FOR 20 PCT, PRESENT WORTH MM$	270.5
FOR 25 PCT, PRESENT WORTH MM$	216.5
FOR 30 PCT, PRESENT WORTH MM$	174.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROBABLE RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	515	0.0	0.0	1.7	0.0	0.0	(0.1)	0.0	0.0	1.7	1.7
12-31-2018	861	0.3	0.0	17.9	0.0	0.0	(0.0)	0.5	0.0	17.4	18.1
12-31-2019	1,055	0.4	0.1	24.5	0.0	0.0	0.2	1.4	0.0	22.9	37.6
12-31-2020	2,357	0.9	0.3	56.7	12.7	0.0	0.0	4.8	0.0	39.1	67.9
12-31-2021	3,296	1.2	0.4	81.3	0.0	0.0	0.6	7.3	17.7	55.7	107.2
12-31-2022	3,225	1.2	0.4	81.3	0.0	0.0	0.6	6.3	39.5	34.9	129.5
12-31-2023	3,370	1.2	0.4	86.1	0.0	0.0	0.6	5.1	20.1	60.3	164.7
12-31-2024	3,352	1.2	0.4	87.1	0.0	0.0	0.6	5.0	20.4	61.1	197.0
12-31-2025	2,673	1.0	0.3	70.3	0.0	0.0	0.6	3.8	16.5	49.4	220.8
12-31-2026	1,722	0.6	0.1	45.5	0.0	0.0	0.2	1.5	11.0	32.9	235.2
12-31-2027	1,979	0.7	0.2	54.0	0.0	0.0	(0.3)	1.6	13.2	39.6	251.0
12-31-2028	1,850	0.7	0.1	51.6	0.0	0.0	(0.7)	1.5	12.7	38.1	264.7
12-31-2029	1,459	0.5	0.1	41.2	0.0	0.0	(1.0)	1.2	10.2	30.7	274.9
12-31-2030	1,074	0.4	0.0	30.6	0.0	0.0	(1.0)	0.9	7.7	23.1	281.7
12-31-2031	800	0.3	0.0	23.2	0.0	0.0	(0.6)	0.4	5.9	17.6	286.5
12-31-2032	614	0.2	0.0	18.1	0.0	0.0	(0.3)	0.0	4.6	13.8	289.9
12-31-2033	366	0.1	0.0	10.9	0.0	0.0	0.1	0.0	2.7	8.1	291.8
12-31-2034	1,333	0.5	0.0	41.6	4.2	(44.3)	34.6	0.0	0.7	46.4	301.2
12-31-2035	0	0.0	0.0	0.0	0.0	46.6	0.0	0.0	0.0	(46.6)	292.6
12-31-2036											
TOTAL		11.5	2.9	823.6	16.9	2.3	34.1	41.3	182.8	546.1	292.6
CUM PROD		0.0	0.0								
ULTIMATE		11.5	2.9								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	327.1
FOR 15 PCT, PRESENT WORTH MM$	226.9
FOR 20 PCT, PRESENT WORTH MM$	181.5
FOR 25 PCT, PRESENT WORTH MM$	149.0
FOR 30 PCT, PRESENT WORTH MM$	125.1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROVED + PROBABLE (2P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	OIL (MMBBL)	SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	3,603	0.2	0.0	11.8	12.2	0.0	6.2	0.1	0.0	(6.7)	(6.7)
12-31-2018	4,864	1.8	0.0	100.9	133.1	0.0	25.2	1.5	0.0	(58.9)	(61.9)
12-31-2019	9,242	3.4	0.6	211.5	99.0	0.0	27.7	7.3	0.0	77.4	4.2
12-31-2020	11,660	4.3	1.0	275.4	71.4	0.0	29.5	12.4	0.0	162.1	129.9
12-31-2021	12,899	4.7	1.1	311.1	49.0	0.0	31.1	15.5	17.7	197.8	269.4
12-31-2022	11,743	4.3	1.0	289.3	6.1	0.0	31.7	13.1	59.6	178.8	384.0
12-31-2023	10,103	3.7	0.8	254.1	6.2	0.0	32.4	9.4	51.5	154.6	474.1
12-31-2024	8,964	3.3	0.6	230.1	6.3	0.0	32.2	7.8	45.9	137.8	547.1
12-31-2025	7,240	2.6	0.4	188.8	4.7	0.0	32.1	5.3	36.7	110.0	600.1
12-31-2026	5,155	1.9	0.1	136.0	4.8	0.0	32.0	2.2	24.3	72.8	632.0
12-31-2027	5,061	1.8	0.2	137.2	4.9	0.0	31.8	2.1	24.6	73.8	661.4
12-31-2028	4,693	1.7	0.1	130.1	5.0	0.0	31.6	1.8	22.9	68.8	686.3
12-31-2029	4,125	1.5	0.1	116.6	5.1	0.0	31.4	1.4	19.7	59.1	705.7
12-31-2030	3,584	1.3	0.0	103.2	5.2	0.0	31.4	0.9	16.4	49.3	720.4
12-31-2031	2,909	1.1	0.0	85.5	4.0	0.0	32.3	0.4	12.2	36.7	730.4
12-31-2032	2,380	0.9	0.0	71.5	4.0	0.0	33.0	0.0	8.6	25.8	736.8
12-31-2033	1,658	0.6	0.0	50.7	4.1	0.0	34.1	0.0	3.1	9.3	738.9
12-31-2034	1,333	0.5	0.0	41.6	4.2	0.0	34.6	0.0	0.7	2.1	739.3
12-31-2035	0	0.0	0.0	0.0	0.0	46.6	0.0	0.0	0.0	(46.6)	730.7
12-31-2036											
TOTAL		39.5	6.0	2,745.5	429.2	46.6	540.2	81.1	344.0	1,304.3	730.7
CUM PROD		115.1	0.0								
ULTIMATE		154.6	6.0								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	813.1
FOR 15 PCT, PRESENT WORTH MM$	568.8
FOR 20 PCT, PRESENT WORTH MM$	452.0
FOR 25 PCT, PRESENT WORTH MM$	365.5
FOR 30 PCT, PRESENT WORTH MM$	299.8

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

POSSIBLE RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	465	0.0	0.0	1.5	0.0	0.0	(0.1)	0.0	0.0	1.6	1.6
12-31-2018	762	0.3	0.0	15.9	0.0	0.0	0.2	0.9	0.0	14.9	15.5
12-31-2019	1,138	0.4	0.1	26.4	0.0	0.0	0.2	1.8	0.0	24.3	36.3
12-31-2020	2,419	0.9	0.3	58.0	0.0	0.0	0.5	5.5	0.0	52.0	76.6
12-31-2021	2,186	0.8	0.3	53.0	0.0	0.0	0.5	5.1	35.1	12.4	85.3
12-31-2022	2,045	0.7	0.2	50.6	0.0	0.0	0.5	4.8	11.3	33.9	107.1
12-31-2023	1,754	0.6	0.2	44.3	0.0	0.0	0.5	4.3	9.9	29.7	124.4
12-31-2024	1,623	0.6	0.2	42.0	0.0	0.0	0.5	3.0	9.6	28.9	139.7
12-31-2025	2,402	0.9	0.3	64.2	0.0	0.0	0.5	3.7	15.0	45.0	161.4
12-31-2026	3,342	1.2	0.4	91.3	0.0	0.0	0.5	5.2	21.4	64.1	189.4
12-31-2027	1,787	0.7	0.2	48.6	0.0	0.0	0.5	2.8	11.3	33.9	202.9
12-31-2028	1,291	0.5	0.1	35.1	0.0	0.0	0.5	1.8	8.2	24.5	211.8
12-31-2029	1,726	0.6	0.2	48.5	0.0	0.0	0.6	2.1	11.5	34.4	223.1
12-31-2030	1,944	0.7	0.2	56.1	0.0	0.0	0.4	2.1	13.4	40.3	235.2
12-31-2031	2,013	0.7	0.1	59.4	0.0	0.0	(0.8)	1.8	14.6	43.9	247.1
12-31-2032	2,010	0.7	0.1	60.5	0.0	0.0	(1.8)	1.7	15.2	45.5	258.3
12-31-2033	2,269	0.8	0.0	69.6	0.0	0.0	(3.2)	1.3	17.9	53.7	270.4
12-31-2034	2,043	0.7	0.0	64.0	0.0	0.0	(3.2)	0.8	16.6	49.8	280.6
12-31-2035	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	280.6
12-31-2036											
TOTAL		12.0	3.0	889.2	0.0	0.0	(3.3)	48.8	210.9	632.7	280.6
CUM PROD		0.0	0.0								
ULTIMATE		12.0	3.0								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE	
FOR 8 PCT, PRESENT WORTH MM$	322.9
FOR 15 PCT, PRESENT WORTH MM$	205.7
FOR 20 PCT, PRESENT WORTH MM$	158.6
FOR 25 PCT, PRESENT WORTH MM$	127.3
FOR 30 PCT, PRESENT WORTH MM$	105.6

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN THE
PRINOS BASIN, OFFSHORE GREECE

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	OIL (MMBBL)	SALES GAS (BCF)	GROSS REVENUE[1] (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	ROYALTY (MM$)	CORPORATE TAX (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	4,068	0.2	0.0	13.3	12.2	0.0	6.1	0.1	0.0	(5.1)	(5.1)
12-31-2018	5,626	2.1	0.0	116.8	133.1	0.0	25.4	2.3	0.0	(44.0)	(46.4)
12-31-2019	10,380	3.8	0.8	237.8	99.0	0.0	28.0	9.1	0.0	101.7	40.4
12-31-2020	14,078	5.1	1.3	333.5	71.4	0.0	30.0	17.9	0.0	214.1	206.5
12-31-2021	15,084	5.5	1.4	364.1	49.0	0.0	31.6	20.6	52.7	210.2	354.7
12-31-2022	13,788	5.0	1.2	339.9	6.1	0.0	32.2	17.9	70.9	212.8	491.1
12-31-2023	11,857	4.3	1.0	298.5	6.2	0.0	32.8	13.7	61.4	184.3	598.5
12-31-2024	10,587	3.9	0.8	272.1	6.3	0.0	32.7	10.8	55.6	166.7	686.8
12-31-2025	9,642	3.5	0.7	253.0	4.7	0.0	32.6	9.0	51.7	155.0	761.5
12-31-2026	8,497	3.1	0.6	227.2	4.8	0.0	32.5	7.4	45.6	136.9	821.4
12-31-2027	6,849	2.5	0.4	185.8	4.9	0.0	32.3	4.9	35.9	107.8	864.3
12-31-2028	5,984	2.2	0.2	165.2	5.0	0.0	32.1	3.6	31.1	93.3	898.1
12-31-2029	5,852	2.1	0.2	165.1	5.1	0.0	31.9	3.5	31.2	93.5	928.8
12-31-2030	5,528	2.0	0.2	159.3	5.2	0.0	31.7	3.0	29.9	89.6	955.6
12-31-2031	4,922	1.8	0.1	145.0	4.0	0.0	31.5	2.1	26.9	80.6	977.5
12-31-2032	4,390	1.6	0.1	132.0	4.0	0.0	31.2	1.7	23.8	71.3	995.1
12-31-2033	3,927	1.4	0.0	120.3	4.1	0.0	30.9	1.3	21.0	63.0	1,009.3
12-31-2034	3,375	1.2	0.0	105.5	4.2	0.0	31.3	0.8	17.3	51.9	1,019.9
12-31-2035	0	0.0	0.0	0.0	0.0	46.6	0.0	0.0	0.0	(46.6)	1,011.2
12-31-2036											
TOTAL		51.5	9.0	3,634.7	429.2	46.6	536.9	130.0	554.9	1,937.0	1,011.2
CUM PROD		115.1	0.0								
ULTIMATE		166.6	9.0								

[1] APPROXIMATELY 1 PERCENT OF THE GROSS REVENUE IS FROM SULFUR SALES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE	
FOR 8 PCT, PRESENT WORTH MM$	1,135.9
FOR 15 PCT, PRESENT WORTH MM$	774.5
FOR 20 PCT, PRESENT WORTH MM$	610.6
FOR 25 PCT, PRESENT WORTH MM$	492.8
FOR 30 PCT, PRESENT WORTH MM$	405.3

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

EXECUTIVE SUMMARY

NETHERLAND, SEWELL & ASSOCIATES, INC.

EXECUTIVE SUMMARY
PRINOS BASIN
OFFSHORE GREECE

1.1 SCOPE OF PROJECT

As requested, we have estimated the gross (100 percent) proved, probable, and possible reserves and future revenue, as of October 31, 2017, for certain oil and gas properties located in the Prinos Basin, offshore Greece. Also as requested, we have estimated the gross (100 percent) contingent and prospective resources, as of October 31, 2017, for certain oil and gas properties located in the Prinos Basin, offshore Greece. Energean Oil & Gas SA (Energean) owns 100 percent interest in these properties. We completed our evaluation on or about December 20, 2017. This report has been prepared using price and cost parameters specified by Energean, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$).

The location of Energean's Prinos Basin assets is shown on the location map in Figure 1.6.1, and a stratigraphic column for Greece is shown in Figure 1.6.2. Estimates of reserves, contingent resources, and prospective resources by asset are included in the tables following the certificates of qualification and in the technical discussions for each asset.

1.2 OVERVIEW OF PRINOS BASIN ASSETS

Energean owns 100 percent interest in multiple licenses in the Prinos and South Kavala development areas. Energean's Prinos Basin assets include Prinos, Epsilon, and Prinos North Fields; Athos, Delta, and Kazaviti Discoveries; Prinos SE Ext Prospect; and Alpha and Omicron Leads. South Kavala Field supplies fuel gas for operations. Omicron is a lead, but it has not been evaluated in this report because available details are currently being reviewed by Energean.

Prinos Field was discovered with the drilling of the Prinos-1 well in 1974. Development of Prinos and South Kavala Fields began in 1979, and production started from both fields in 1981. Prinos North Field, located to the northwest of Prinos Field, was discovered with the drilling of the Prinos North-2 well in 1994, and production started in the field in 1996. In 1998, the fields were shut in because of declining production and low oil prices. The original concession agreement was terminated, and the assets were returned to the Greek State in 1999.

The Prinos and South Kavala development areas were licensed again in 1999 to Kavala Oil SA (Kavala), which was jointly owned by Eurotechniki SA and the Kavala Association of Employees, which owned 67 and 33 percent, respectively. A new contract, the Prinos and South Kavala Exploitation Contract (Law No 2779) was awarded to Kavala at the end of 1999. Epsilon Field was discovered in 2000 and appraised in 2002. Regal Petroleum PLC (Regal) acquired a majority stake in Eurotechniki SA in 2003 and drilled a number of exploration wells in 2004 and 2005.

In 2007, Energean acquired all the shares of Eurotechniki SA from Regal. Kavala assigned all of its participation rights in the Prinos and South Kavala development areas to Energean in 2008 and 2009. By a service agreement dated November 2015, Kavala provides support services to Energean in the operation of the fields.

The duration of the development license for Prinos and Prinos North Fields, which preceded Law No 2779, is 25 years, according to article 5 of Law 2289/1995, and it starts from the date of execution of Law No 2779,

which was December 1999. The duration of the development license for the South Kavala development area, as same is being defined in Law 4135/2013, was extended to November 2018. The duration of the exploration stage for the exploration sub-areas of the Prinos and South Kavala development areas is 8 years, according to paragraph 1 of article 5 of Law 2289/1995, and starts from March 19, 2013. In case of discovery of a new field that can be commercially developed, the duration of the development license of the development sub-area to be awarded is 25 years, according to article 5 of Law 2289/1995. As regards Epsilon Field in particular, the start date of its development license is June 15, 2004.

The duration of any development license may be further extended for a maximum of two 5-year periods, according to paragraph 13 of article 5 of Law 2289/1995. The duration of the Prinos and Prinos North development license may be further extended for a maximum of two 5-year periods, according to paragraph 13 of article 5 of Law 2289/1995 and provided that such assets have been developed in the best technical way and the production is maintained above the threshold of economic viability.

License expiration dates and possible extensions are shown in the following table:

Field	Development License Expiration Date	Extensions Available
Prinos	December 2024	2 at 5 years each
Epsilon	June 15, 2029	2 at 5 years each
Prinos North	December 2024	2 at 5 years each
South Kavala	November 2017	November 2018

1.3 REPORT BASIS

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers. As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.

1.4 DATA SOURCES AND AVAILABILITY

Energean provided a comprehensive technical database for our assessment and allowed full access to its technical staff through email, teleconferences, and a series of meetings held in September 2017. Data provided included the following:

- Numerous presentations and technical reports regarding recent Energean operations and technical studies
- Petrel projects containing the following:
  - Cultural data, well location data, and directional surveys
  - Well log data, formation tops, and fluid contacts

  - Seismic data and check shot data (where available)
  - Depth structure maps and fault interpretation
  - Static model and volumetric calculations
- Historical monthly oil, gas, and water production data and water injection data by well
- Available flowing well test data for new discovery wells and recent drillwells
- Hydrocarbon sample data and pressure-volume-temperature (PVT) analysis
- Summaries of fiscal terms for all assets
- Operator records and budgets for operating expenses and capital expenditures for all developments
- Historical monthly hydrocarbon pricing data for producing properties
- Energean cash flow economics model

Additional data specific to each asset is listed in the technical discussion for each asset. The review and analysis of the information provided enabled us to make our assessments of the reserves, contingent resources, and prospective resources of the company.

1.5 EVALUATION METHODOLOGY

1.5.1 PETROPHYSICAL EVALUATION

For Epsilon and Prinos North Fields and Delta and Kazaviti Discoveries, independent petrophysical calculations were carried out using available core and well log data supplied by Energean. A three-component porosity-water saturation model was used that independently accounts for the conductivity associated with structural and laminar shale inclusions in the hydrocarbon-bearing sands as well as the conductivity associated with the pore-lining diagenetic clays within the sands. Shale volume estimates were made using the gamma ray, neutron porosity, and bulk density measurements. Porosity was estimated from the shale-corrected bulk density and neutron porosity measurements. The properties of the diagenetic clays used in the model were based on values encountered in reservoirs with a similar depositional environment.

A range of water saturations were estimated based on a range of shale distribution assumptions. Low case estimates assumed that a higher percentage of shale was distributed as structural shale clasts, while high case estimates assumed that a higher percentage of shale was distributed as laminations. Base case estimates assumed an equal distribution of structural shale clasts and shale laminations.

Formation water resistivity was estimated using standard Pickett Plot analysis methods and found to be 0.05 ohm-meters at 75°F. Shale volume and distribution corrections were applied to the deep resistivity measurements, and then the Dual-Water Model developed by Schlumberger was used to compute the water saturation for each case. Where available, core data were used for calibrating the petrophysical modeling results and for defining net pay cutoff criteria using a conventional porosity-versus-permeability cutoff methodology. A total porosity cutoff of 9 percent was used. Additionally, net pay was confined to intervals with total shale volume less than 40 percent and total water saturation less than 65 percent. For

areas with petrophysical analysis, interpreted well logs and summaries of petrophysical parameters are included with the technical discussions.

A different petrophysical analysis was performed for the Athos Discovery and is described in the technical discussion for that asset.

1.5.2 PERFORMANCE ANALYSIS

Decline curve analysis (DCA) and analogy were the primary tools for projecting reserves for currently producing wells. These methodologies are generally considered the most reliable methods for projecting reserves in producing wells with significant production histories and consistent operating conditions. In general, DCA consists of using a well's historical production characteristics to forecast future production trends. For Prinos, Epsilon, and Prinos North Fields, we performed two types of analysis for producing wells: area-level DCA and individual well-level DCA.

The area-level DCA includes plotting total oil, gas, and water production versus time on a semi-log scale. We also review the water cut (percent water production) and water-oil ratio trends versus cumulative production on a semi-log scale. The area-level plots include only currently active producers so that performance is not masked by wells that are no longer producing. This analysis is helpful in identifying overall production trends and is not subject to allocation issues that may arise when looking at data on a per-well basis. These projections also help to account for the significant number of ongoing workover programs that are not specifically forecast by the operator but are a significant part of the work activity in the field. The major disadvantage of the area-level projections is that they do not expose performance variations in different parts of the area.

Individual well-level DCA is essentially the same as the area-level DCA except that it is performed on each producing well. Assuming reasonable production allocations within a field, this analysis should give a more accurate forecast of reserves for the current completion in each well and thus the field as a whole assuming no additional workover activities. This analysis can help identify variations in well performance throughout the field and areas with remaining unswept hydrocarbons. We can also forecast operating expenses and field life more accurately because variable costs can be assigned on a per-well basis. As additional wells are drilled or as wells reach their variable-cost economic limit, incremental costs will be accurately accounted for.

1.5.3 PROBABILISTIC ANALYSIS

Probabilistic spreadsheet models were constructed to calculate low, best, and high estimate original oil-in-place (OOIP) and technically recoverable volumes associated with reserves, contingent resources, and prospective resources. The models utilize the Crystal Ball add-in to Excel to run a Monte Carlo simulation of various forecast parameters based on prescribed input parameters.

We determined the type of distribution and input parameters for the various volumetric parameters by individual reservoir. Gross rock volume (GRV) or net sand volume (NSV) input parameters were defined by either a normal or lognormal distribution, with input values typically being represented by bounding conditions such as a spill point or highest known water for the high estimate case, a lowest known hydrocarbon for the low estimate case, or a hydrocarbon-water contact for the most likely case. Tables summarizing the basis for the GRV or NSV calculations by zone are provided as figures in the technical discussions. The remaining volumetric parameters of net-to-gross ratio (NTG), porosity, hydrocarbon saturation, formation volume factor (FVF), and recovery factor were usually input as triangular distributions with minimum, most likely, and maximum values. NTG, porosity, hydrocarbon saturation, and FVF are

based on the petrophysical calculations and PVT data available and are provided in figures in the technical discussion sections for each asset.

Recovery factors are based on analogous fields in the region or dynamic modeling results. Dependencies between all input parameters are addressed in the probabilistic models, and correlation coefficients range from 0.0 to 0.7. All volumetric input parameters and resulting OOIP and technically recoverable volumes associated with reserves, contingent resources, and prospective resources are summarized on figures in the respective technical discussions.

1.5.4 ECONOMICS

The Netherland, Sewell & Associates, Inc. (NSAI) proprietary economics program was used to forecast production by well and reserves category for the wells in the Prinos and South Kavala development areas. The oil and gas flowstreams were then included in a cash flow model that incorporated operating costs, capital costs, and fiscal terms. The model used for this area is a spreadsheet model that was developed by Energean. We reviewed and adjusted the model as necessary and then used it to calculate reserves and future net revenue.

The Prinos and South Kavala development areas are located in the North Aegean Sea in approximately 30 meters (m) of water. Prinos and Prinos North Fields have been developed with two platforms: Alpha (A) and Beta (B), each having 12-slot capacity. Charlie (C) platform will be installed in 2020 to allow for additional infill drilling in Prinos Field. Produced fluids flow by subsea pipeline to a treating plant onshore. There the oil is prepared for sales by removing hydrogen sulfide (H_2S). Epsilon Field is located 3 kilometers (km) from Prinos Field. It will initially be produced by extended-reach drillwells drilled from B platform and in 2019 will be developed with the 15-slot Lambda platform. Energean plans to install equipment at the onshore treating plant to be able to sell excess associated gas not used for fuel. Gas sales from each field have been estimated using the field-processed gas-oil ratio (GOR) from each field multiplied by the ratio of each field's oil production to total oil production.

As requested, this report has been prepared using oil and gas price parameters specified by Energean. Oil prices are based on October 31, 2017, Dated Brent prices and adjustments are based on contractual deductions to the Dated Brent price along with the average differential of the Urals oil price to the Dated Brent oil price for December 2016 through November 2017. Oil prices also include adjustments for anticipated API gravity produced from the fields. The gas price used in this report is $7.302 per MCF, which is the average price paid by Energean for fuel gas for these properties from October 2016 through September 2017 adjusted for energy content, transportation fees, and market differentials. The sulfur price used in this report is based on a sales contract with a nearby fertilizer plant and is $61.80 per ton after adjustment for transportation costs. All prices are escalated 2 percent on January 1 of each year throughout the lives of the properties.

Operating costs used in this report are based on operating expense records and budgets of Energean, the operator of the properties, and include only direct lease-level and field-level costs. Costs are included for operations and maintenance expenses, electricity costs, and fuel gas purchase costs. Electricity costs include a power consumption factor that is proportional to the amount of daily oil production; Energean estimated this factor using a facility modeling program. This factor is multiplied by the electricity purchase price of $75.90 per megawatt-hour, which is based on the 12-month average of electricity costs charged to Energean from September 2016 through August 2017. As oil production decreases from peak rates, electricity usage will be maintained at peak values based on anticipated power needs of facility equipment at increasing watercut. Fuel gas is purchased from the Greek Public Gas Corporation when Energean doesn't produce sufficient fuel gas from Prinos and South Kavala areas. The price used for fuel gas purchase is $10.50 per MCF and is based on the 12-month average price from October 2016 through September 2017. Following the completion of the drilling program in 2021, operations and maintenance

costs are gradually reduced based on reductions in staffing levels. As requested, operating expenses are escalated 2 percent on January 1 of each year throughout the lives of the properties for inflation. Details of our 1P, 2P, and 3P operating expense estimates by expense category are shown in Figures 1.6.3 through 1.6.5.

Capital costs used in this report were provided by Energean and are based on budgeted expenditures and authorizations for expenditure (AFEs). Epsilon Field platform costs are $61.6 million. C platform installation costs are estimated to be $20 million. Drilling costs of $237.9 million are included in the proved plus probable (2P) case to drill or sidetrack 23 production wells and 3 injection wells. Two workovers requiring the rig are included at approximately $1.8 million each in 2018. Other workover costs of $3.0 million per year in 2018 and 2019, $2.0 million per year from 2020 through 2030, and $1.0 million per year from 2031 to the end of field life are included for recompletions and stimulations. In the AFEs that Energean has provided for the wells and workovers, a 20 percent contingency is included; this additional cost is included in our estimates of capital costs. Prinos facility costs include $3.0 million in 2018 for excess gas facilities to allow Energean to sell gas when it produces more that it requires for fuel gas consumption. General facility maintenance capital of $0.3 million in 2017, $2.0 million in 2018, $3.0 million in 2019, $3.5 million per year from 2020 through 2024, and $2.0 million per year thereafter are also included. Costs of $31.62 million in the proved (1P) case and $32.62 million in the 2P and proved plus probable plus possible (3P) cases are included for abandonment of the platforms, wells, and production facilities at the economic limit of the field. These costs are the net costs to Energean. Energean is responsible for 50 percent of the abandonment costs, and the state is responsible for the remaining 50 percent. Because the development plan is the same in the 2P and 3P cases, capital costs and abandonment costs are also the same. As requested, capital costs and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure for inflation. Details of our 1P and 2P/3P capital expenditure estimates are shown in Figures 1.6.6 and 1.6.7.

Following the completion of the drilling program, Energean plans to sell the drilling rig for $10 million. The proceeds from the drilling rig sale are not included in our estimates of future net revenue. A tax loss carry forward of $319 million is included in the economic assessment.

Basic fiscal terms and economic parameters used in the economics model are shown in the following table:

Fiscal Terms

Contract Type	Royalty-tax
Operator	Energean
First Production	1981
Interest (%)	100
Royalty (%)	0 to 10
Corporate and Municipality Tax (%)	25.00
Oil Price Adjustment ($/Barrel)	-7.44



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Figure 1.6.1

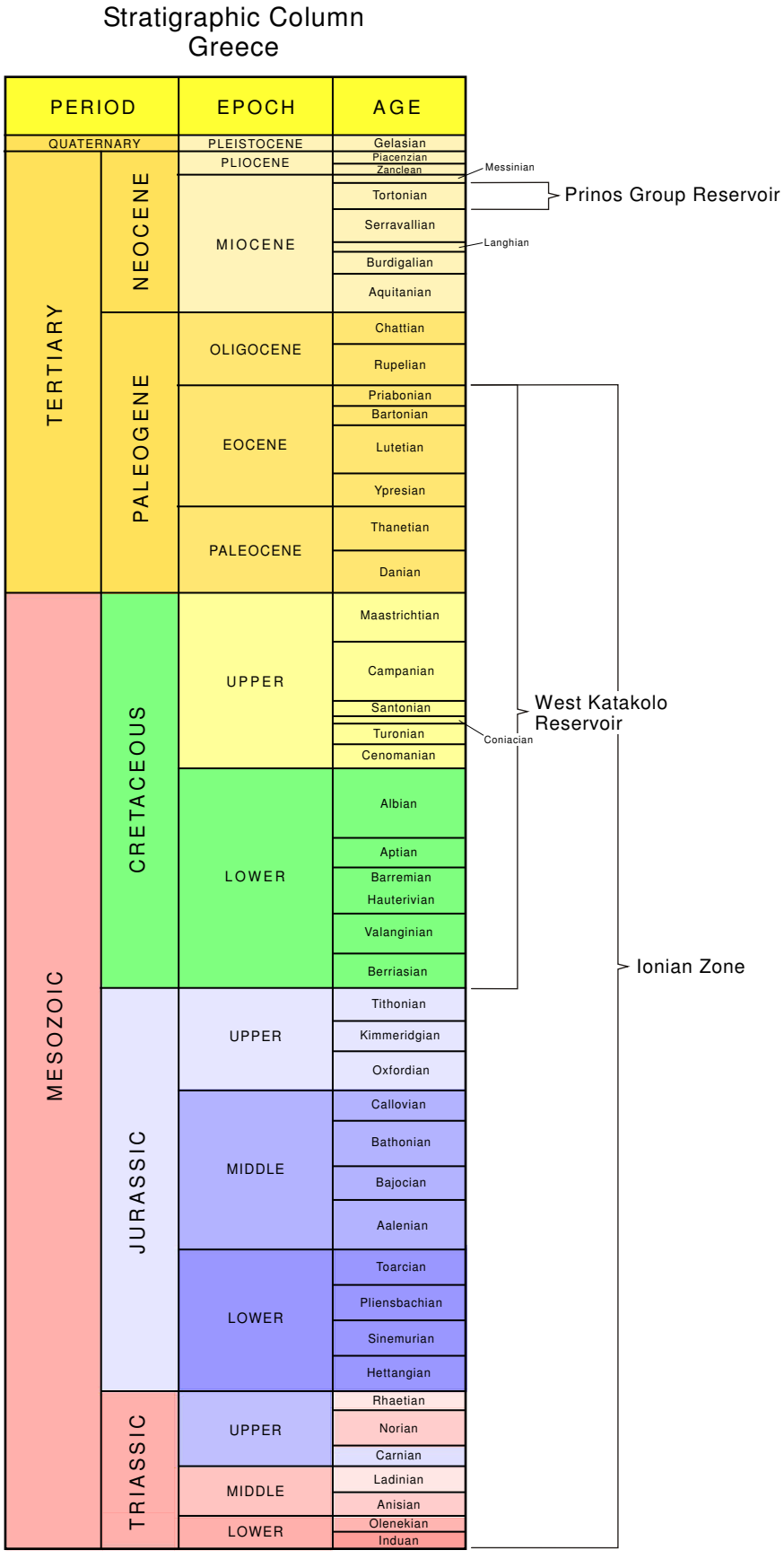

Stratigraphic Column
Greece
PERIOD
EPOCH
AGE
QUATERNARY
PLEISTOCENE
Gelasian
PLIOCENE
Piacenzian
Zanclean
Messinian
Tortonian
Prinos Group Reservoir
Serravallian
Langhian
Burdigalian
Aquitanian
Chattian
Rupelian
Priabonian
Bartonian
Lutetian
Ypresian
Thanetian
Danian
Maastrichtian
Campanian
Santonian
West Katakolo
Reservoir
Turonian
Coniacian
Cenomanian
Albian
Aptian
Barremian
Hauterivian
Valanginian
Berriasian
Ionian Zone
Tithonian
Kimmeridgian
Oxfordian
Callovian
Bathonian
Bajocian
Aalenian
Toarcian
Pliensbachian
Sinemurian
Hettangian
Rhaetian
Norian
Carnian
Ladinian
Anisian
Olenekian
Induan
TERTIARY
NEOCENE
PALEOGENE
MESOZOIC
CRETACEOUS
JURASSIC
TRIASSIC
MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
UPPER
LOWER
MIDDLE

Figure 1.6.2

1P GROSS (100 PERCENT) OPERATING EXPENSE ESTIMATES
PRINOS BASIN, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Gross Fixed Field Expenses (MM$)															
Category	2017[1]	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Thereafter	Total
Operations and Maintenance	4.8	19.1	20.2	21.1	21.5	21.5	21.5	20.8	20.2	19.5	18.8	18.2	17.5	16.8	46.6	308.1
Electricity Purchase	1.3	5.5	6.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	20.1	106.7
Fuel Gas Purchase	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.1	1.3	1.5	7.8	13.4
Total	6.3	24.7	26.4	27.8	28.2	28.2	28.2	27.5	26.9	26.6	26.4	26.0	25.5	25.0	74.4	428.1

Note: Costs shown are prior to escalation for inflation.

[1] Includes only costs for the fourth quarter of 2017.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

2P GROSS (100 PERCENT) OPERATING EXPENSE ESTIMATES
PRINOS BASIN, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Category	Gross Fixed Field Expenses (MM$)															
	2017[1]	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Thereafter	Total
Operations and Maintenance	4.8	19.1	20.2	20.8	21.5	21.5	21.5	20.8	20.2	19.5	18.8	18.2	17.5	16.8	60.7	322.0
Electricity Purchase	1.3	5.6	6.5	7.0	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	28.9	121.6
Fuel Gas Purchase	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	8.9	9.2
Total	6.2	24.7	26.6	27.8	28.7	28.7	28.7	28.1	27.4	26.7	26.1	25.4	24.7	24.2	98.5	452.8

Note: Costs shown are prior to escalation for inflation.

[1] Includes only costs for the fourth quarter of 2017.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

3P GROSS (100 PERCENT) OPERATING EXPENSE ESTIMATES
PRINOS BASIN, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Gross Fixed Field Expenses (MM$)															
Category	2017[1]	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Thereafter	Total
Operations and Maintenance	4.8	19.1	20.2	20.8	21.5	21.5	21.5	20.8	20.2	19.5	18.8	18.2	17.5	16.8	60.7	322.0
Electricity Purchase	1.4	5.8	6.7	7.5	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	30.7	128.6
Fuel Gas Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5
Total	6.1	24.9	26.9	28.3	29.2	29.2	29.2	28.5	27.8	27.2	26.5	25.8	25.2	24.5	91.9	451.1

Note: Costs shown are prior to escalation for inflation.

[1] Includes only costs for the fourth quarter of 2017.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

1P GROSS (100 PERCENT) CAPITAL EXPENDITURE ESTIMATES
PRINOS BASIN, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Category	Gross Capital Expenditures (MM$)						
	2017[1]	2018	2019	2020	2021	Thereafter	Total
Platforms and Facilities							
Prinos	0.3	5.0	3.0	3.5	3.5	28.5	43.8
Lambda	0.0	42.8	18.8	0.0	0.0	0.0	61.6
Charlie	0.0	0.0	10.0	10.0	0.0	0.0	20.0
Subtotal	0.3	47.8	31.8	13.5	3.5	28.5	125.4
Drilling	10.0	76.0	60.3	39.8	39.8	0.0	225.9
Workovers	2.0	6.7	3.0	2.0	2.0	21.0	36.7
Abandonment[2]	0.0	0.0	0.0	0.0	0.0	31.6	31.6
Total	12.2	130.5	95.2	55.3	45.3	81.1	419.6
Number of Wells Drilled	1	8	7	4	4	0	24

Note: Costs shown are prior to escalation for inflation.

(1) Includes only costs for the fourth quarter of 2017.
(2) Abandonment occurs in 2034 in the 1P case and 2035 in the 2P and 3P cases.

Figure 1.6.6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

2P AND 3P GROSS (100 PERCENT) CAPITAL EXPENDITURE ESTIMATES
PRINOS BASIN, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Category	Gross Capital Expenditures (MM$)						
	2017[1]	2018	2019	2020	2021	Thereafter	Total
Platforms and Facilities							
Prinos	0.3	5.0	3.0	3.5	3.5	30.5	45.8
Lambda	0.0	42.8	18.8	0.0	0.0	0.0	61.6
Charlie	0.0	0.0	10.0	10.0	0.0	0.0	20.0
Subtotal	0.3	47.8	31.8	13.5	3.5	30.5	127.4
Drilling	10.0	76.0	60.3	51.8	39.8	0.0	237.9
Workovers	2.0	6.7	3.0	2.0	2.0	22.0	37.7
Abandonment[2]	0.0	0.0	0.0	0.0	0.0	32.6	32.6
Total	12.2	130.5	95.2	67.3	45.3	85.1	435.6
Number of Wells Drilled	1	8	7	6	4	0	26

Note: Costs shown are prior to escalation for inflation.

(1) Includes only costs for the fourth quarter of 2017.
(2) Abandonment occurs in 2034 in the 1P case and 2035 in the 2P and 3P cases.

Figure 1.6.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

PRINOS FIELD

TECHNICAL DISCUSSION
PRINOS FIELD
OFFSHORE GREECE

2.1 OVERVIEW

Prinos Field is located approximately 8 km northwest of Thasos Island and 18 km south of the Greek coast in a water depth of approximately 30 m. Figure 1.6.1 shows a location map of the area.

Prinos Field was discovered when the exploration well Prinos-1 was drilled in 1974. Production started in 1981, and water injection was initiated in December 1981. Over 55 wells have been drilled in the field with 9 wells producing and 4 active water injection wells as of October 31, 2017. The field production rate was 3,075 barrels of oil per day (BOPD) in October 2017 with cumulative production of 110.6 million barrels (MMBBL) of oil.

Since the end of 2015, 6 wells have been drilled in Prinos Field; these wells produce over 90 percent of the current production. Although Prinos is a mature field, there are still many opportunities to drill for bypassed oil. The current development plan includes drilling 15 new wells from the current A and B platforms and the new C platform to be installed in 2020 as well as workovers on several A and B platform wells.

We have estimated reserves for the A, B, and C Reservoirs of Prinos Field; contingent resources for the A, B, C, and D Reservoirs of Prinos Field; and prospective resources for the B and C Reservoirs in a separate structure located in the southeast extension of the main field (the separate structure is referred to herein as "Prinos SE Ext Prospect").

2.1.1 RESERVES

We estimate the gross (100 percent) reserves for the A, B, and C Reservoirs of Prinos Field, as of October 31, 2017, to be:

	Gross (100%) Reserves	
Category	Oil (MMBBL)	Sales Gas (BCF)
Proved Developed	3.8	0.0
Proved Undeveloped	9.0	1.5
Proved (1P)	12.8	1.5
Probable	5.1	1.4
Proved + Probable (2P)	17.8	2.9
Possible	7.3	1.8
Proved + Probable + Possible (3P)	25.2	4.8

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil volumes are expressed in MMBBL; a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

2.1.2 CONTINGENT RESOURCES

The contingent resources shown in this report for the A, B, and C Reservoirs in Prinos Field are contingent upon improved economic parameters and improved recovery rates. The contingent resources shown in this report for the D Reservoir in Prinos Field are contingent upon creation of a development plan and commitment from Energean to develop the reservoir.

We estimate the unrisked gross (100 percent) contingent resources for Prinos Field, as of October 31, 2017, to be:

	Unrisked Gross (100%) Contingent Resources	
Category	Oil (MMBBL)	Sales Gas (BCF)
A, B, and C Reservoirs		
Low Estimate (1C)	2.7	0.9
Best Estimate (2C)	15.6	4.9
High Estimate (3C)	29.1	9.2
D Reservoir		
Low Estimate (1C)	0.0	0.0
Best Estimate (2C)	0.0	0.0
High Estimate (3C)	0.1	0.0
Total		
Low Estimate (1C)	2.8	0.9
Best Estimate (2C)	15.6	4.9
High Estimate (3C)	29.2	9.2

Totals may not add because of rounding.

The oil volumes shown include crude oil only.

2.1.3 PROSPECTIVE RESOURCES

We estimate the unrisked and risked gross (100 percent) prospective oil resources for the B and C Reservoirs of Prinos SE Ext Prospect, as of October 31, 2017, to be:

	Gross (100%) Prospective Oil Resources	
Category	Unrisked (MMBBL)	Risked (MMBBL)
Low Estimate	1.8	0.4
Best Estimate	2.6	0.6
High Estimate	3.7	0.8

The oil volumes shown include crude oil only.

2.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation in addition to the data listed in the Executive Summary are listed below:

- Petrophysical data for select wells including computer-processed interpretation (CPI) logs and associated reports

2.3 GEOLOGIC SUMMARY

2.3.1 OVERVIEW

The Prinos Basin was formed during large-scale regional extension that began in the Miocene. This rift basin is characterized by rapid subsidence and sedimentation along with listric and normal faults that trend either northwest-southeast or northeast-southwest. Mapped on good-quality 3-D seismic data, Prinos Field is a large rollover anticline downthrown on a major northwest-southeast-trending listric fault with a thick (300 m) sedimentary sequence of Miocene age turbiditic deposits called the Prinos Group. These deposits are overlain by a thick evaporitic interval of salt and anhydrite that acts as a seal.

Oil productive intervals in the Prinos Group are referred to as the A, B, and C Reservoirs. A deeper interval of the Prinos Group, the D Reservoir, has been tested but is not producing. A stratigraphic column is shown on Figure 1.6.2.

Southeast of Prinos Field, there is a smaller, deeper anticline at the B and C Reservoir level that is referred to as the Prinos SE Ext Prospect. It is separated from Prinos Field by a structural saddle.

Depth structure maps are shown on Figures 2.6.1 through 2.6.4. Tables showing the basis for GRV calculations are shown on Figures 2.6.5 and 2.6.6.

2.3.2 PRINOS FIELD

2.3.2.1 A, B, and C Reservoirs

The Miocene age A, B, and C Reservoirs of the Prinos Group are stacked channel and distal fan turbidites interbedded with and separated by correlatable shales. Sands are well distributed throughout the field. The A Reservoir is further divided into two sublayers, A1 and A2, and is the thickest of the three reservoirs with an average gross thickness of 176 m. The B and C Reservoirs have average gross thicknesses of 53 and 51 m, respectively. The Prinos oil reservoirs can be found at depths of approximately -2,500 to -2,800 m true vertical depth subsea (TVDSS).

As previously mentioned, the structural trap is a rollover anticline downthrown on a northwest-southeast-trending listric fault. The fault dips to the southwest and bounds the structure to the northeast. The Prinos structure exhibits low relief with internal faulting subparallel to the main fault.

All three reservoirs demonstrate excellent reservoir quality. The A Reservoir has the best rock quality of the three reservoirs. Based on petrophysical analyses provided by Energean, average NTG is 85 percent, average effective porosity is 18 percent, and average water saturation is 21 percent. Compared to the A Reservoir, the B Reservoir has a higher NTG of 89 percent but a lower average effective porosity of 15 percent and a higher water saturation of 29 percent. The C Reservoir is between the A and B Reservoirs

with respect to hydrocarbon pore thickness, with an average NTG of 89 percent, an average effective porosity of 16 percent, and an average water saturation of 29 percent. The petrophysical parameters input into the probabilistic model also incorporate Energean's petrophysical analysis.

Contacts for the three reservoirs are independent of each other. The contacts are derived from well log analysis; however, averaged depths are used from various wells because of inconsistent contact depths from well to well. The low side case contacts used for the A, B, and C Reservoirs are -2,711, -2,751, and -2,791 m TVDSS, respectively; these depths are based on Energean's estimates of contacts. For the high side case, we used the NSAI estimates of -2,730, -2,768, and -2,805 m TVDSS for the A, B, C Reservoirs, respectively.

The A, B, and C Reservoirs are producing, and estimated volumes are classified as reserves and contingent resources.

2.3.2.2 D Reservoir

The D Reservoir lies directly below the C Reservoir in Prinos Field and shares its structural setting. This reservoir has been penetrated by several wells; however, few have seen the full section. The base is defined by the major listric fault that sets up Prinos Field and where salt is typically encountered. This results in a wide range of gross thicknesses between 26 and 255 m. Because of this wide range, appropriate rock volumes are based on net sand mapping.

Very little petrophysical analysis is available for the D Reservoir. Data available suggest lower porosity (approximately 5 percent) and higher water saturation (approximately 55 percent) in comparison to the A, B, and C Reservoirs. Although sand distribution in the D Reservoir is generally good, sand continuity is not well understood.

The D Reservoir has been tested but is not producing, and estimated volumes are classified as contingent resources.

2.3.3 PRINOS SE EXT PROSPECT

2.3.3.1 B and C Reservoirs

Located to the southeast of Prinos Field is a separate structural feature at the B and C Reservoir levels. The feature is a smaller, deeper anticline with four-way closure that is separated from Prinos Field by a structural saddle. While both reservoirs exhibit favorable trap geometry, it should be noted that the Prinos SE Ext Prospect structural highs are deeper than the corresponding contact at Prinos Field.

Because of its close proximity to Prinos Field, roughly 1,000 m away, reservoir quality is expected to be similar. Best case GRV estimates for the B and C Reservoirs are estimated to the spill points at -2,859 and -2,905 m TVDSS, respectively. Low case estimates are 90 percent of the best case estimate.

We conducted a geologic risk assessment for each reservoir using a four-component methodology based on Otis and Schneidermann[1] to measure the probability of geologic success (P_g). Geologic risk assessment addresses the probability of success for discovering hydrocarbons without regard to commerciality. Each of the four elements is assigned a value from 0.0 to 1.0, and the product of the four components is the

[1] Otis, R.M. and N. Schneidermann, 1997, A Process for Evaluating Exploration Prospects, *AAPG Bulletin*, Volume 81, Number 7, pages 1087-1109.

overall P_g. Principal geologic elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Because of the subjective nature of geologic risk assessment, any such assessment is highly dependent on the experience of the evaluators, the data available to define each prospect, the regional data describing reservoir and production characteristics, and the historical local and regional hydrocarbon discovery success rates. Otis and Schneidermann define a P_g greater than 0.50 as very low risk, a P_g between 0.50 and 0.25 as low risk, a P_g between 0.25 and 0.125 as moderate risk, a P_g between 0.125 and 0.063 as high risk, and a P_g below 0.063 as very high risk exploration opportunities. Our final P_g estimate for this lead is 0.22, with the biggest risk component being timing and migration.

The B and C Reservoirs in Prinos SE Ext Prospect have not been tested, and estimated volumes are classified as prospective resources.

2.4 PETROPHYSICAL SUMMARY

Three third-party consultants completed detailed petrophysical evaluations for wells in Prinos Field. The majority of interpreted wells were interpreted by Geneva Petroleum Consultants International. Resulting CPI logs and associated reports were provided to NSAI by Energean, and these analyses were utilized for the petrophysical averages used in this report.

An effective porosity cutoff of 7 percent with a shale volume less than 50 percent was applied to the Geneva CPI logs to calculate petrophysical summations.

2.5 RESERVOIR ENGINEERING SUMMARY

2.5.1 DEVELOPMENT HISTORY

Prinos Field was discovered in 1974 and brought on production in 1981 with an initial 24 development wells. Water injection was initiated in December 1981. Production peaked at 27 thousand barrels of oil per day in 1985 before beginning to decline to a rate of 4,000 BOPD by the end of 1998. The field was temporarily shut in for a year. In December 1999, production resumed at 4,000 BOPD but continued to decline to 1,500 BOPD by 2007. Production fluctuated between 1,000 and 1,500 BOPD until seeing the impact of the drilling of the PB-34 in 2011 and the PA-35 in 2015, which proved the potential for infill drilling in the B and C Reservoirs. The subsequent drilling of the PA-36, PA-40, and PA-41 wells in 2016 highlighted the remaining oil potential for infill drilling in the A Reservoir. The drilling of these 3 wells and the PA-33 and PA-38 wells in 2017 has seen production increase to over 3,000 BOPD again. A total of 55 wells have been drilled in Prinos Field, with 9 currently producing and 4 active water injection wells. Over 90 percent of the production currently comes from the 6 wells drilled since the end of 2015. Significant additional drilling is planned to find bypassed oil.

The Prinos offshore complex includes two 8-leg, 12-slot drilling platforms (A and B), an 8-leg processing platform, a flare, and interconnected bridges. Crude oil is flowed to shore through an 18-km, 8-inch-diameter pipeline to an onshore oil and gas processing facility near Kavala where crude oil, condensate, and sulfur are sold.

During the first half of 2017, there were significant problems with asphaltene dropout and blockage in the production wells. Energean studied the issue and made operational changes to rectify the problem. First, recent dual completions are being replaced with single completions and future wells will be single

completions to allow deeper injection of chemicals closer to the perforations. Second, production rates are being limited to values that maintain bottomhole pressures above the asphaltene onset pressure; this rate is typically around 600 BOPD.

2.5.2 RESERVES DETERMINATION

Prinos Field produces an undersaturated sour crude with a gravity of 27 to 30° API and high sulfur and asphaltene content. The field was slightly overpressured, with an initial reservoir pressure ranging from 5,700 to 6,250 psia. The initial solution GOR is approximately 675 standard cubic feet per stock tank barrel (SCF/STB), with a high H_2S content ranging from 30 percent in the B and C Reservoirs to 60 percent in the A Reservoir. The initial FVF is approximately 1.37 reservoir barrels per stock tank barrel (RB/STB), and the bubblepoint pressure ranges from 1,190 to 2,060 psia. The in-situ viscosity of the oil ranges from 0.55 to 0.80 centipoise (cp) at initial conditions, which is favorable for waterflooding.

Current reservoir pressures range significantly from 1,750 to 4,000 psia, indicating that there is compartmentalization in the field and that historically water injection has not maintained voidage in the field, although currently water injection is sufficient to maintain reservoir voidage.

To validate Energean OOIP estimates, a probabilistic volumetric model was constructed to calculate low, best, and high estimate OOIP associated with reserves and contingent resources. We determined the type of distribution and input parameters for the various volumetric parameters by reservoir. GRV was input as a normal distribution with 95 percent confidence level (P95) and 5 percent confidence level (P05) input values based on the low and high estimate cases discussed earlier. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions with input values based on the Energean-modeled petrophysical parameters. Oil FVF was also modeled as a triangular distribution with input values based on established field parameters.

Volumetric input parameters associated with oil reserves for Prinos Field are summarized in Figure 2.6.7. The resulting OOIP volumes calculated in the probabilistic model are summarized in Figure 2.6.8. OOIP is 277.1 MMBBL in the 1P case, 302.7 MMBBL in the 2P case, and 329.9 MMBBL in the 3P case. Based on an estimated ultimate recovery (EUR) of 128.7 MMBBL of oil in the 2P case, this indicates a recovery factor of 42.4 percent for the Prinos A, B, and C intervals.

DCA was used to estimate 1P, 2P, and 3P producing reserves from the existing 9 producing wells. The current development plan for the A, B, and C Reservoirs in the main part of the field and the A Reservoir in the southeast extension area includes drilling 15 new wells from the current A and B platforms and the new C platform to be installed in 2020 as well as workovers and sidetracks on 2 A platform wells and 4 B platform wells. Two A platform wells planned to be drilled at the end of 2017 will be followed by 5 B platform wells and then 8 additional wells from the C platform. Ten of these wells will be producers and will target bypassed oil in the A, B, and C Reservoirs in the main part of the field. The technically recoverable 1P, 2P, and 3P oil volumes of 0.70, 0.95, and 1.35 MMBBL, respectively, for these wells are estimated based on the average EUR for the 7 new wells drilled in Prinos Field since 2013. Two additional wells will target the A Reservoir in the southeast area of the field. The technically recoverable 1P, 2P, and 3P oil volumes of 1.00, 1.25, and 1.50 MMBBL are based on using similar recoveries from the main field structure for the southeast extension A Reservoir volumes. The remaining 3 planned drillwells will be water injection wells. Two workovers are planned on A and B platform wells, and 4 sidetracks are planned on B platform wells. We had sufficient data to forecast volumes for 2 of the producers. The PA-33 workover has behind-pipe intervals that are scheduled to be added at various times during 2018. The technically recoverable 1P, 2P, and 3P oil volumes of 0.550, 0.850, and 1.500 MMBBL, respectively, are based on analogy to the current completion intervals. The PB-34 workover will shut off an open water interval. Technically recoverable 2P and 3P oil volumes of 0.180 and 0.415 MMBBL, respectively, are based on performance analysis.

The following table identifies the timing, reserves category, field area, reservoir, and type of project for the work programs forecast for the Prinos A, B, and C Reservoirs:

Well	Date of First Prod	Reserves Category	Field Area/ Reservoir	Type
PB-34	11/2017	2P	Main A, B, C	Workover – water shut-off
PA-37	1/2018	1P	Main A, B, C	Drillwell
PA-33	4/2018	1P	Main A, B, C	Workover – add perforations
PA-32	7/2018	1P	Main A, B, C	Drillwell
PB-39	11/2018	1P	Southeast A	Drillwell
PB-42	2/2019	1P	Main A, B, C	Drillwell
PB-43	4/2019	1P	Main A, B, C	Drillwell
PB-44	6/2019	1P	Main A, B, C	Drillwell
PC-46	9/2020	1P	Main A, B, C	Drillwell
PC-47	11/2020	1P	Southeast A	Drillwell
PC-49	2/2021	1P	Main A, B, C	Drillwell
PC-51	5/2021	1P	Main A, B, C	Drillwell
PC-52	7/2021	1P	Main A, B, C	Drillwell
PC-53	8/2021	1P	Main A, B, C	Drillwell

Daily production forecasts for the reserves are shown by reserves category in Figure 2.6.9. The flowstreams account for field downtime, which is expected to be reduced to 2 percent by 2020. In the 1P case, downtime accounted for in the flowstreams is 10 percent through the end of 2018, 5 percent in 2019, and 2 percent in 2020. In the 2P case, downtime is 5 percent through the end of 2018, 4 percent in 2019, and 2 percent in 2020. In the 3P case, downtime is 2 percent through the end of 2020. Associated gas volumes are based on a field-processed GOR of 315 SCF/STB, as detailed in the Economics section of the Executive Summary.

2.5.3 CONTINGENT RESOURCES DETERMINATION

Additional contingent resources are estimated for the Prinos A, B, and C intervals based on additional recovery of up to 50 percent. These contingent resources are calculated incrementally to the 3P technically recoverable EUR of 140.8 MMBBL of oil. 1C, 2C, and 3C technically recoverable oil volumes are estimated at 2.7, 15.6, and 29.1 MMBBL, respectively. Associated gas volumes are based on an expected field-processed GOR of 315 SCF/STB, as detailed in the Economics section of the Executive Summary.

Contingent resources are also estimated for the D Reservoir of Prinos Field, which has been tested by 3 wells. Test data for the D Reservoir are shown on Figure 2.6.10.

A probabilistic spreadsheet model was constructed to calculate 1C, 2C, and 3C OOIP and gross (100 percent) technically recoverable oil volumes associated with the D Reservoir. Net sand volume (NSV) was input as a normal distribution with 90 percent confidence level (P90) and 50 percent confidence level (P50) input values. The P50 input is based on the NSAI NSV and the P90 input is 80 percent of this volume. Net-pay-to-net-sand ratio, porosity, and hydrocarbon saturation were assigned triangular distributions and were based on NSAI petrophysical evaluation. Oil FVF and recovery factors were also modeled as triangular distributions. Oil FVF is based on established Prinos Field parameters, and recovery factors are based on analogy to similar poor reservoirs.

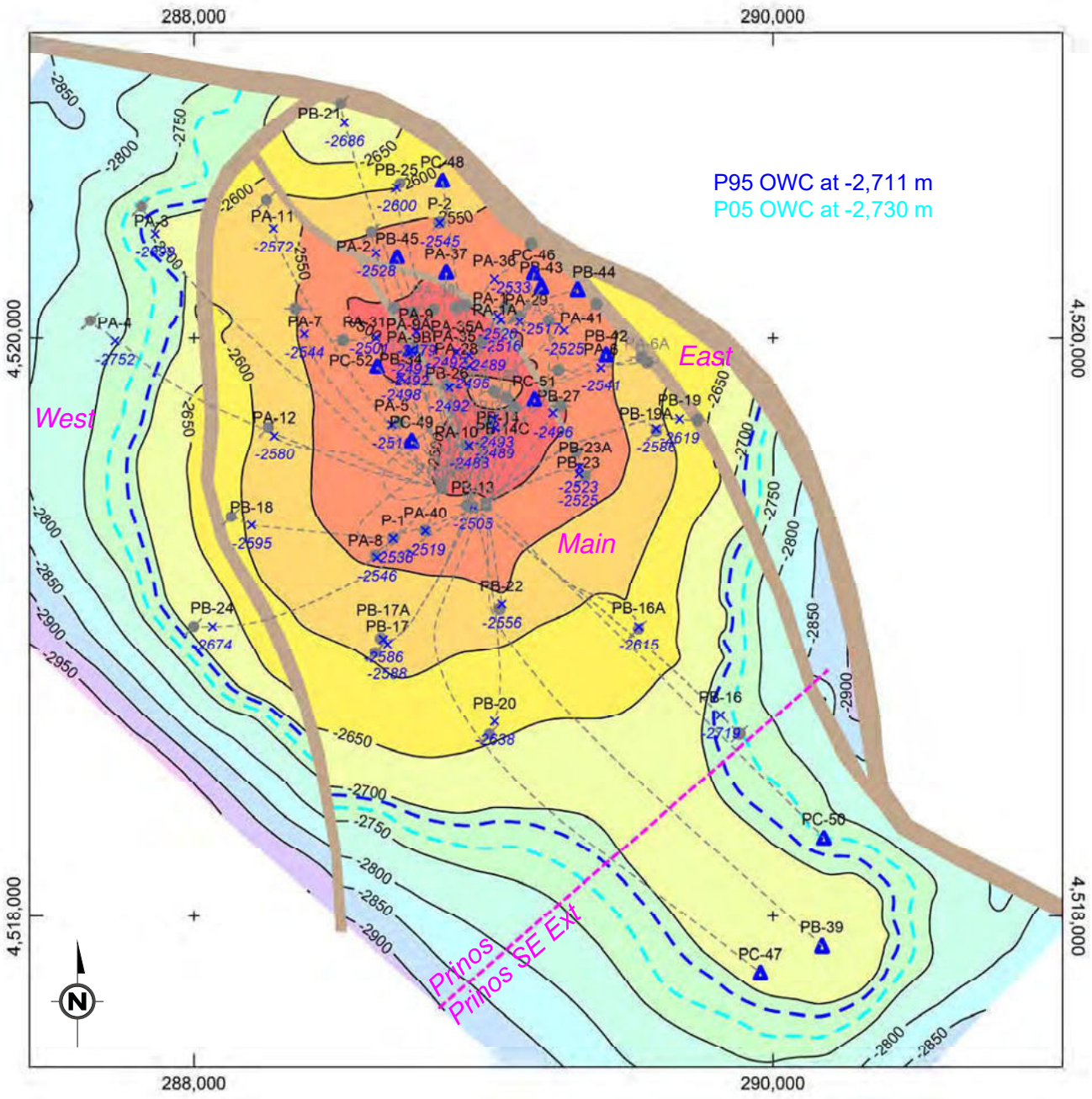
All volumetric input parameters for D Reservoir in Prinos Field are summarized in Figure 2.6.11. The resulting OOIP and gross (100 percent) technically recoverable volumes associated with contingent oil resources calculated in the probabilistic model are summarized in Figure 2.6.12. Because economic

analysis has not been performed on these volumes, contingent oil resources for the D Reservoir are equal to the technically recoverable volumes shown on Figure 2.6.12.

2.5.4 PROSPECTIVE RESOURCES DETERMINATION

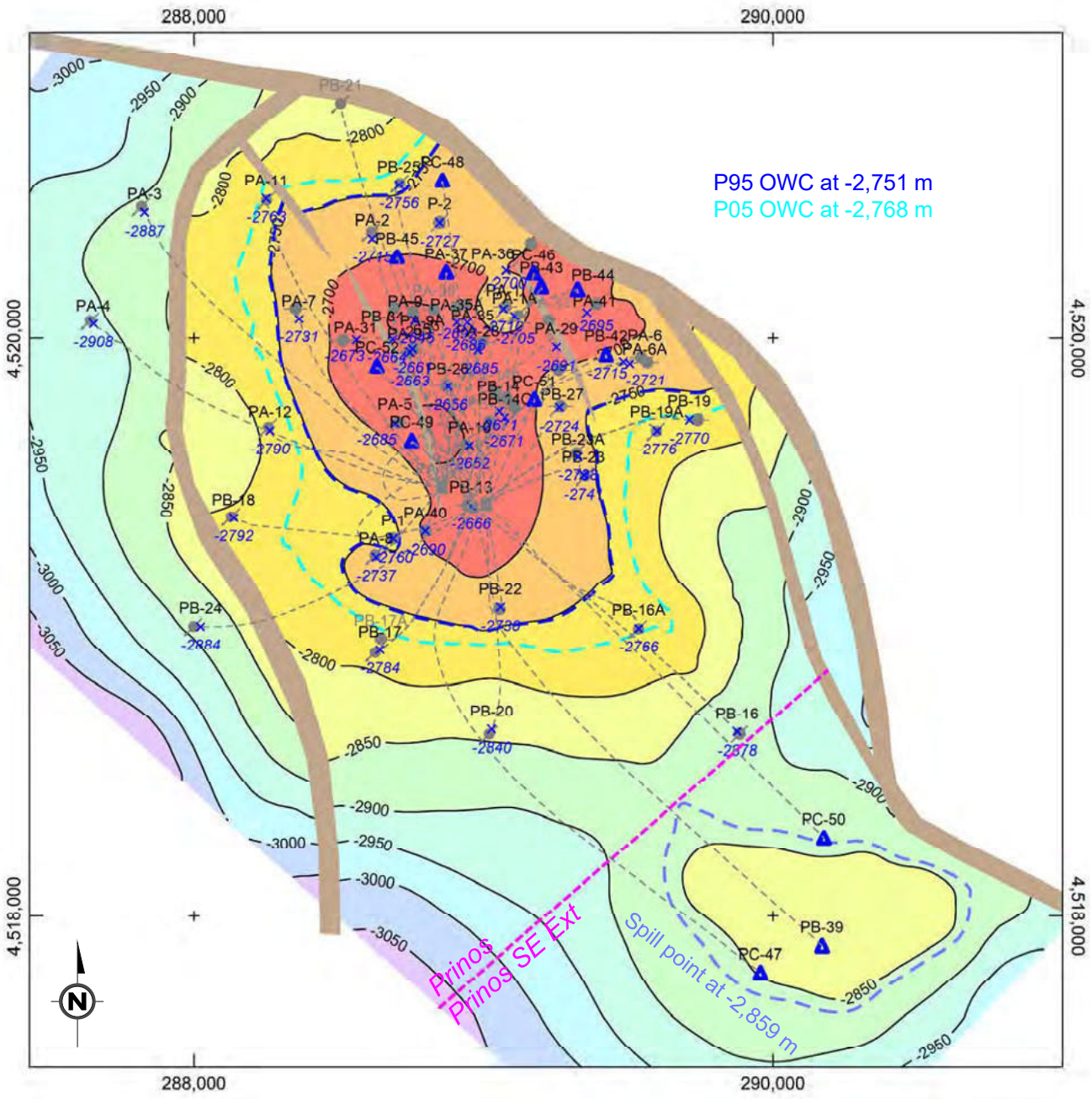
A probabilistic spreadsheet model was constructed to calculate low, best, and high estimate OOIP and prospective oil resources for the B and C Reservoirs in Prinos SE Ext Prospect. We determined the type of distribution and input parameters for the various volumetric parameters by reservoir. GRV input parameters were defined by a normal distribution with P90 and P50 input parameters, as previously discussed. The remaining volumetric parameters of NTG, porosity, hydrocarbon saturation, FVF, and recovery factor were all input as triangular distributions. Probability ranges for all volumetric parameters were estimated based on analogous fields in the region and our knowledge of similar reservoirs.

All volumetric input parameters for the B and C Reservoirs in Prinos SE Ext Prospect are summarized on Figure 2.6.13. The resulting unrisked and risked OOIP and gross (100 percent) prospective resources calculated in the probabilistic model are summarized on Figures 2.6.14 and 2.6.15.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2.6.1



Legend

Δ Undeveloped Location

Prinos Field and Prinos SE Ext Prospect
Offshore Greece

Depth Structure
Top B Reservoir

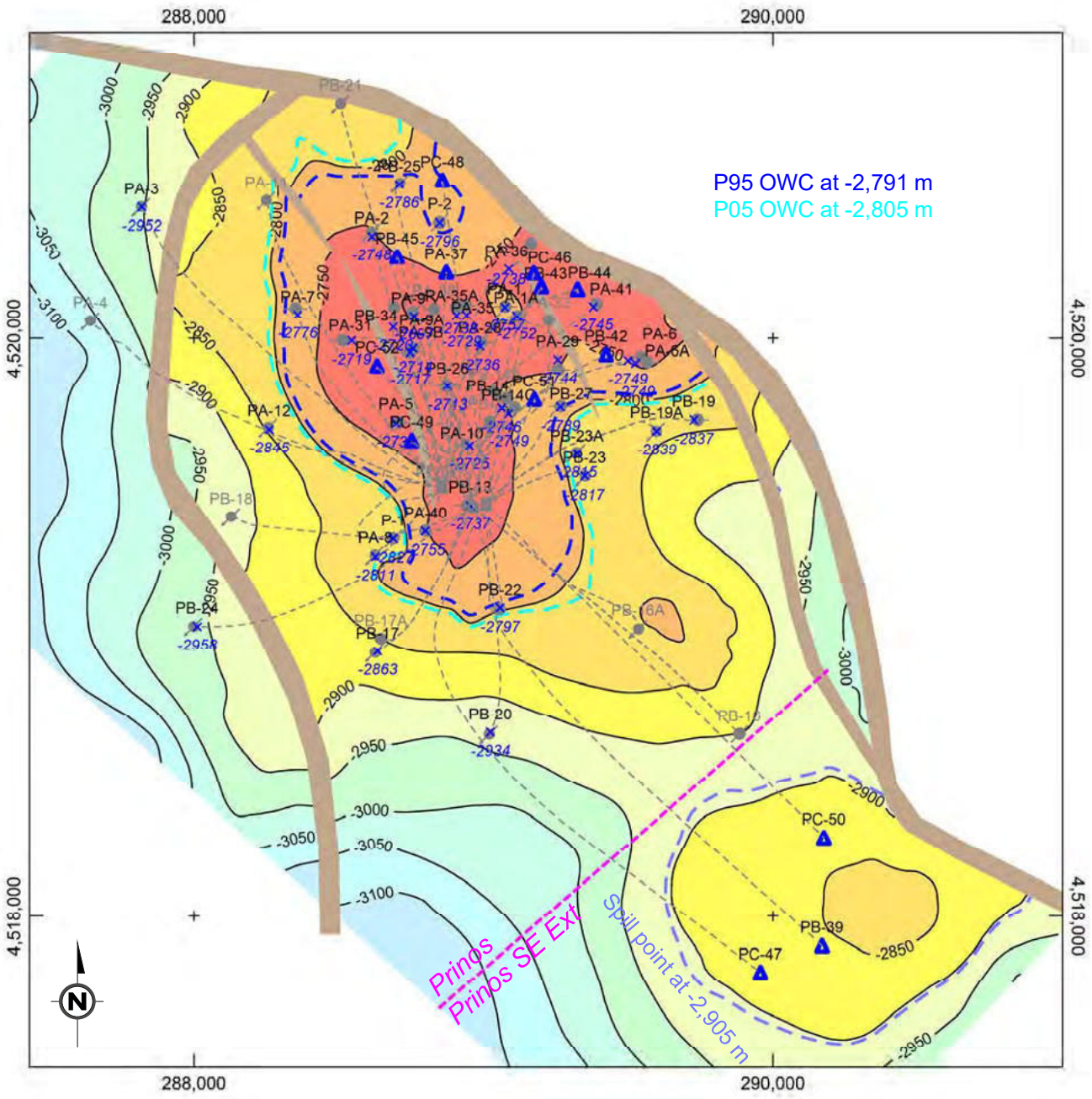
Contour Interval: 50 m

SCALE IN METERS

0 250 500 750 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2.6.2



Legend

Δ Undeveloped Location

Prinos Field and Prinos SE Ext Prospect
Offshore Greece

Depth Structure
Top C Reservoir

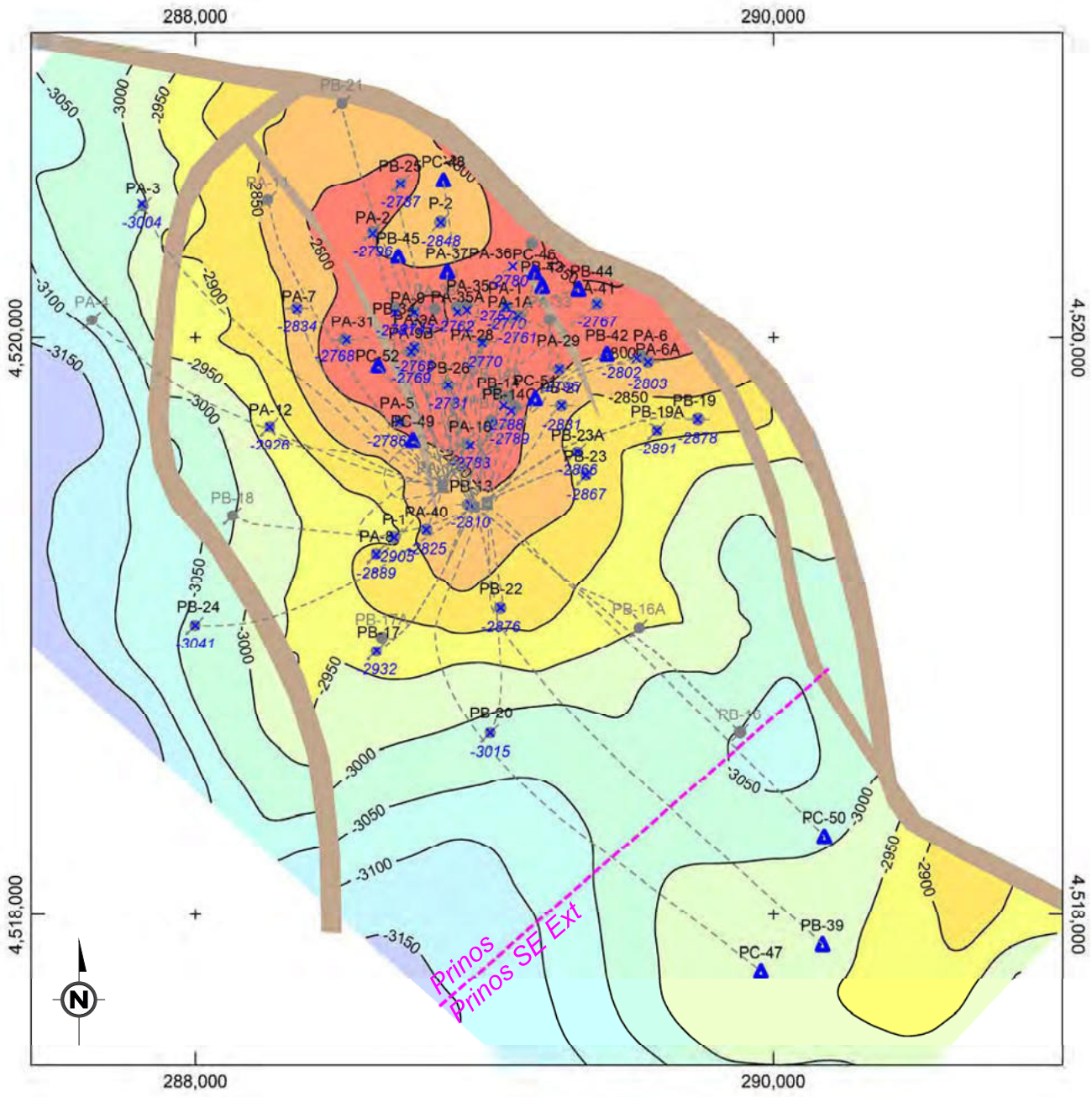
Contour Interval: 50 m

SCALE IN METERS

0 250 500 750 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2.6.3



Legend

Δ Undeveloped Location

Prinos Field and Prinos SE Ext Prospect
Offshore Greece

Depth Structure
Top D Reservoir

Contour Interval: 50 m

SCALE IN METERS

0 250 500 750 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2.6.4

GROSS ROCK VOLUME BASIS
PRINOS FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	High Estimate Case	Distribution Type
A	1P	OWC at -2,711 m TVDSS	OWC at -2,730 m TVDSS	Normal
B	1P	OWC at -2,751 m TVDSS	OWC at -2,768 m TVDSS	Normal
C	1P	OWC at -2,791 m TVDSS	OWC at -2,805 m TVDSS	Normal

Figure 2.6.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

GROSS ROCK VOLUME BASIS
PRINOS SE EXT PROSPECT, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	Best Estimate Case	Distribution Type
B	Low	Best estimate -10%	Spill point at -2,859 m TVDSS	Normal
C	Low	Best estimate -10%	Spill point at -2,905 m TVDSS	Normal

Figure 2.6.6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH OIL RESERVES
PRINOS FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category[1]	Gross Rock Volume (Acre-Feet) P95	Gross Rock Volume (Acre-Feet) P50	Gross Rock Volume (Acre-Feet) P05	Net-to-Gross Ratio (Decimal) Min	Net-to-Gross Ratio (Decimal) Most Likely	Net-to-Gross Ratio (Decimal) Max	Porosity (Decimal) Min	Porosity (Decimal) Most Likely	Porosity (Decimal) Max
A	1P	355,379	N/A	413,171	0.819	0.846	0.900	0.170	0.175	0.179
B	1P	42,039	N/A	53,209	0.830	0.888	0.900	0.150	0.153	0.159
C	1P	34,138	N/A	42,313	0.850	0.887	0.900	0.160	0.164	0.175

Reservoir	Category[1]	Hydrocarbon Saturation (Decimal) Min	Hydrocarbon Saturation (Decimal) Most Likely	Hydrocarbon Saturation (Decimal) Max	Formation Volume Factor (RB/STB) Min	Formation Volume Factor (RB/STB) Most Likely	Formation Volume Factor (RB/STB) Max
A	1P	0.700	0.794	0.850	1.350	1.364	1.380
B	1P	0.650	0.714	0.750	1.350	1.367	1.380
C	1P	0.650	0.714	0.750	1.350	1.367	1.380

[1] For reservoirs categorized as 1P, we have estimated 1P, 2P, and 3P technically recoverable volumes associated with reserves.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE
ASSOCIATED WITH OIL RESERVES
PRINOS FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Original Oil-in-Place (MMBBL) 1P	2P	3P
A	230.1	254.7	280.7
B	22.7	25.6	28.5
C	20.0	22.4	24.8
Arithmetic Sum[(1)]	272.8	302.6	334.1
Probabilistic Sum	277.1	302.7	329.9

(1) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

Figure 2.6.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF DAILY PRODUCTION RATES FOR RESERVES (BARRELS/DAY)
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
PRINOS FIELD, OFFSHORE GREECE

PERIOD ENDING	PROVED (1P)				PROVED + PROBABLE (2P)				PROVED + PROBABLE + POSSIBLE (3P)			
		UNDEVELOPED BY PLATFORM				UNDEVELOPED BY PLATFORM				UNDEVELOPED BY PLATFORM		
	DEVELOPED	ALPHA/BETA	CHARLIE	TOTAL	DEVELOPED	ALPHA/BETA	CHARLIE	TOTAL	DEVELOPED	ALPHA/BETA	CHARLIE	TOTAL
12-31-2017	2,931	0	0	2,931	3,421	0	0	3,421	3,864	0	0	3,864
12-31-2018	2,440	968	0	3,407	3,160	1,052	0	4,212	3,837	1,098	0	4,935
12-31-2019	1,858	2,893	0	4,751	2,577	3,197	0	5,774	3,454	3,416	0	6,870
12-31-2020	1,370	2,459	377	4,206	2,064	3,016	414	5,494	2,919	3,577	454	6,951
12-31-2021	1,044	1,689	3,043	5,777	1,707	2,116	3,289	7,112	2,582	3,060	3,618	9,260
12-31-2022	768	1,141	2,826	4,734	1,363	1,469	3,105	5,938	2,224	2,169	3,560	7,952
12-31-2023	575	795	1,854	3,223	1,106	1,072	2,128	4,306	1,913	1,581	2,559	6,053
12-31-2024	436	569	1,260	2,265	909	812	1,536	3,257	1,661	1,206	1,929	4,796
12-31-2025	335	416	883	1,634	756	634	1,152	2,542	1,453	952	1,507	3,911
12-31-2026	258	311	634	1,203	635	506	891	2,032	1,280	771	1,210	3,260
12-31-2027	202	236	466	904	535	412	707	1,653	1,134	637	993	2,763
12-31-2028	158	182	349	689	451	341	572	1,363	1,009	536	829	2,374
12-31-2029	124	142	265	532	381	285	470	1,136	900	457	703	2,060
12-31-2030	99	111	205	415	321	240	392	954	804	394	604	1,802
12-31-2031	79	88	160	327	271	204	330	806	718	344	524	1,586
12-31-2032	63	70	126	259	229	173	280	683	642	303	459	1,404
12-31-2033	50	56	100	206	192	147	238	578	574	268	406	1,248
12-31-2034	0	0	0	0	161	125	203	489	513	240	361	1,114

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TEST DATA
D RESERVOIR, PRINOS FIELD, OFFSHORE GREECE

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Reservoir	Duration (hour)	Choke (inch)	Oil Rate Avg (BOPD)	S_w (%)	GOR (SCF/STB)	FWHP (psig)	Gravity (°API)	Comment
P-3[1]	1	3,012	3,056	C, D	4	N/A	49	88	N/A	N/A	N/A	Tested interval watered out during flow test
PB-14[2]	1D	3,040	3,045	D	12	N/A	4	N/A	N/A	N/A	N/A	Oil rate decline from 6 to 1 BOPD in 12 hours
PB-22	1	2,950	2,970	D	24	N/A	240	N/A	1,260	0	30	Before acid stimulation
PB-22	2	2,950	2,970	D	288	N/A	120		1,260	0	30	After acid stimulation. Test indicated 200 psi depletion.

(1) Perforation intervals are 3,012 to 3,022, 3,027 to 3,033, 3,048 to 3,049, and 3,053 to 3,056.
(2) Perforation intervals are 2,040 to 3,045 and 3,050 to 3,060.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH CONTINGENT OIL RESOURCES
D RESERVOIR, PRINOS FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Net Sand Volume (Acre-Feet)			Net-Pay-to-Net-Sand Ratio (Decimal)			Porosity (Decimal)		
Reservoir	Category[1]	P90	P50	P10	Min	Most Likely	Max	Min	Most Likely	Max
D	1C	2,692	3,365	N/A	0.50	0.59	0.75	0.03	0.05	0.07

		Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
Reservoir	Category[1]	Min	Most Likely	Max	Min	Most Likely	Max	Min	Most Likely	Max
D	1C	0.45	0.55	0.65	1.35	1.36	1.38	0.10	0.15	0.20

[1] For reservoirs categorized as 1C, we have estimated 1C, 2C, and 3C technically recoverable volumes associated with contingent resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH CONTINGENT OIL RESOURCES
D RESERVOIR, PRINOS FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1C	2C	3C	1C	2C	3C	1C	2C	3C
D	0.20	0.32	0.47	0.03	0.05	0.08	13	15	17

(1) Because economic analysis has not been performed on these volumes, contingent oil resources for D Reservoir are equal to the technically recoverable volumes shown.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH PROSPECTIVE OIL RESOURCES
PRINOS SE EXT PROSPECT, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
						Most			Most	
Reservoir	Category[1]	P90	P50	P10	Min	Likely	Max	Min	Likely	Max
B	Low	3,951	4,390	N/A	0.500	0.700	0.888	0.150	0.153	0.159
C	Low	16,096	17,884	N/A	0.500	0.700	0.887	0.160	0.164	0.175

		Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
			Most			Most			Most	
Reservoir	Category[1]	Min	Likely	Max	Min	Likely	Max	Min	Likely	Max
B	Low	0.500	0.600	0.714	1.350	1.367	1.380	0.20	0.30	0.40
C	Low	0.500	0.600	0.714	1.350	1.367	1.380	0.20	0.30	0.40

[1] For reservoirs categorized as low estimate, we have estimated low, best, and high technically recoverable volumes associated with prospective resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
UNRISKED GROSS (100 PERCENT) PROSPECTIVE OIL RESOURCES
PRINOS SE EXT PROSPECT, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Original Oil-in-Place (MMBBL)			Unrisked Gross (100%) Prospective Oil Resources (MMBBL)			Recovery Factor[1] (%)		
	Low	Best	High	Low	Best	High	Low	Best	High
B	1.2	1.6	2.1	0.3	0.5	0.7	26	30	34
C	5.4	7.1	9.1	1.4	2.1	3.1	26	30	34
Arithmetic Sum[2]	6.6	8.7	11.2	1.7	2.6	3.8	26	30	34
Probabilistic Sum	6.8	8.7	10.9	1.8	2.6	3.7	26	30	34

(1) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Prospective Oil Resources by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

(2) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF GROSS (100 PERCENT) UNRISKED AND RISKED PROSPECTIVE OIL RESOURCES
PRINOS SE EXT PROSPECT, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Unrisked Oil (MMBBL)						Risked Oil (MMBBL)					
	P_g	Original In-Place			Gross Recoverable			Original In-Place			Gross Recoverable		
Reservoir	(Decimal)	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
B	0.22	1.22	1.61	2.05	0.31	0.48	0.70	0.27	0.35	0.45	0.07	0.11	0.15
C	0.22	5.37	7.05	9.14	1.38	2.10	3.12	1.17	1.54	2.00	0.30	0.46	0.68
Arithmetic Sum[(1)]		6.58	8.66	11.20	1.69	2.59	3.82	1.44	1.89	2.45	0.37	0.57	0.84
Probabilistic Sum		6.84	8.69	10.91	1.75	2.59	3.74	1.50	1.90	2.39	0.38	0.57	0.82

(1) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

EPSILON FIELD

TECHNICAL DISCUSSION
EPSILON FIELD
OFFSHORE GREECE

3.1 OVERVIEW

Epsilon Field is located approximately 3 km west-northwest of Prinos Field in water depths of 35 to 45 m in the Prinos Basin. Figure 1.6.1 shows a location map of the area. Epsilon Field was discovered in 2000 when the exploration well E-1 was drilled. The structure contains sour light crude of 36° API in Miocene sandstones at a depth of approximately -2,800 m TVDSS. We have estimated reserves and contingent resources for Epsilon Field.

The discovery well for Epsilon Field, E-1, was drilled in 2000 by Eurotechniki. The field was appraised in 2002 with the drilling of a sidetrack, E-1AS, which penetrated the structure approximately 500 m southeast of where the original well penetrated it. After taking operatorship of the field, Energean drilled an extended-reach appraisal and development well, EA-H1, in 2009. This well branched out into two horizontal laterals of approximately 450 and 475 m in length. EA-H1 produced at an initial monthly rate of 2,000 barrels of oil, but it declined to approximately 400 barrels of oil in 13 months. Well productivity decline was attributed to asphaltene precipitation. However, EA-H1 casing was subsequently found collapsed during a workover in February 2011 prompting a sidetrack attempt, which was unsuccessful. EA-H1 was abandoned with a cumulative oil production of 337 thousand barrels (MBBL).

Epsilon Field will have a phased development. First, three development wells will be drilled with the Jupiter rig in 2018. These wells will also serve to further appraise the field by logging the oil-water contact (OWC) and allowing for the collection of additional fluid samples and the exploration of the deeper potential. Once the Lambda platform is completed in early 2019, these three wells will be completed and put on production. Initial well performance will be used to optimize the second drilling phase, planned for late 2019. This phase consists of four to six producers depending upon estimated oil-in-place from phase I well performance. In addition, three to five producers will be converted to injectors to maintain pressure support and prevent asphaltene precipitation.

3.1.1 RESERVES

We have estimated reserves for the A1 and A2 Reservoirs in Epsilon Field. The development license started on June 15, 2004, and has a duration of 25 years with the option of two 5-year extensions. The 1P, 2P, and 3P reserves in this report are estimated through June 15, 2039.

We estimate the gross (100 percent) reserves for Epsilon Field, as of October 31, 2017, to be:

	Gross (100%) Reserves	
Category	Oil (MMBBL)	Sales Gas (BCF)
Proved Undeveloped	13.0	1.4
Proved (1P)	13.0	1.4
Probable	5.4	1.3
Proved + Probable (2P)	18.4	2.8

Category	Gross (100%) Reserves Oil (MMBBL)	Sales Gas (BCF)
Possible	3.5	1.0
Proved + Probable + Possible (3P)	21.9	3.8

Totals may not add because of rounding.

The oil volumes shown include crude oil only.

3.1.2 CONTINGENT RESOURCES

The contingent resources shown in this report for Epsilon Field are contingent upon improved economic parameters and improved recovery rates.

We estimate the unrisked gross (100 percent) contingent resources for Epsilon Field, as of October 31, 2017, to be:

Category	Unrisked Gross (100%) Contingent Resources Oil (MMBBL)	Sales Gas (BCF)
Low Estimate (1C)	0.0	0.0
Best Estimate (2C)	0.1	0.0
High Estimate (3C)	3.7	1.1

The oil volumes shown include crude oil only.

3.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation in addition to the data listed in the Executive Summary are listed below:

- Conventional core data for E-1 and E-1AS and associated routine and special core analysis
- Modular dynamics tests (MDTs) in wells E-1 and E-1AS

3.3 GEOLOGIC SUMMARY

3.3.1 OVERVIEW

Epsilon Field is located in the Prinos Basin, offshore Greece, in the northern Aegean Sea between mainland Greece and Thasos Island. Epsilon Field is across a small saddle west-northwest of Prinos Field and is also productive from the Prinos Group sands. The A Reservoir has successfully been produced in the field. While the B and C Reservoirs have not been penetrated, they have potential for future development.

3.3.2 A RESERVOIR

Mapped with 3-D seismic data, Epsilon Field is an east-west-trending structural feature bounded to the north by the same major listric fault as Prinos Field and to the southwest by another listric fault. The structural high is located in the western part of the field where the two faults come together, and structural dip is generally to the east. Internal faults are also present within the structure but are not considered sealing in our analysis. A depth structure map is shown on Figure 3.6.1.

The A Reservoir, comprising the A1 and A2 sublayers, of the Prinos Group in Epsilon Field is correlated to be age-equivalent to the reservoir of the same name in Prinos Field. However, it is treated as a stratigraphically separate reservoir because of data indicating original reservoir pressure conditions in Epsilon. The A1 and A2 Reservoirs have gross thicknesses of approximately 75 and 25 m, respectively, and can be found at a depth of approximately -2,650 m TVDSS. As in Prinos Field, sands are part of a turbiditic sequence and well distributed throughout the field based on the few current well penetrations. A stratigraphic column is shown on Figure 1.6.2.

Based on our best estimate independent petrophysical analysis, the NTG of the A1 and A2 Reservoirs in the E-1 well are 58 and 33 percent, respectively, with an average overall effective porosity of 12 percent and an average water saturation of 44 percent. Core permeabilities range from 1 to 20 millidarcies. Although the reservoir quality is slightly lower than Prinos Field, it is worthwhile to note that the averages are based on one well and may not be fully representative. Therefore, the petrophysical parameters input into the probabilistic model also incorporate Energean's petrophysical analysis.

In Epsilon Field, no fluid contacts have been penetrated by any well and no water has been produced during production. Volumetric calculations are based on an assumed stratigraphic boundary located at the saddle separating Epsilon and Prinos Fields along with a best estimate lowest known oil (LKO) of -2,945 m TVDSS. A table showing the basis for the GRV calculation is shown on Figure 3.6.2.

The A1 and A2 Reservoirs are currently not producing, and volumes are classified as undeveloped reserves.

3.4 PETROPHYSICAL SUMMARY

The petrophysical evaluation methodology described in Section 1.5.1 of the Executive Summary was used for Epsilon Field. The interpreted well log for E-1 is shown in Figure 3.6.3. The raw log data for E-1AS were deemed of insufficient quality and were excluded from our analysis. The petrophysical summary table for Epsilon Field is shown in Figure 3.6.4.

3.5 RESERVOIR ENGINEERING SUMMARY

3.5.1 DEVELOPMENT HISTORY

After taking operatorship in 2009, Energean drilled the multilateral well EA-H1, which consisted of two horizontal laterals of 450 and 475 m in length. EA-H1 was put on production in January 2010 with an initial production rate of 2,000 BOPD. After only three months of production, a significant drop in well productivity and oil rates was observed. A wireline investigation indicated that blocking due to asphaltene deposition was the cause. Well rates stabilized at approximately 1,200 BOPD for the next two months. Next, Energean cleaned out EA-H1 with mixed results and put the well on gas lift. A 300-BOPD gain from gas lift was realized but quickly disappeared. A second well-cleaning attempt was performed in October 2010.

However, production remained low and was down to 400 BOPD by February 2011 when Energean performed a workover. During the workover, it was confirmed that the casing had collapsed, so the original wellbore was abandoned and a sidetrack attempted. The sidetrack was mechanically unsuccessful, and the well was abandoned with a cumulative oil production of 337 MBBL.

3.5.2 RESERVES DETERMINATION

Several drillstem tests (DSTs) were performed in the E-1 and E-1AS wells testing the A1 Reservoir. Test data for Epsilon Field are shown on Figure 3.6.5.

During the E-1AS DSTs, separator samples were collected and recombined for PVT analysis. PVT study was limited to constant volume expansion and differential liberation experiments. Because separator tests were not carried out, we normalized the experimental solution GOR of 650 SCF/STB to the producing GOR of 325 SCF/STB observed in the EA-1H well and adjusted the oil FVF accordingly. Estimated fluid and reservoir properties are summarized below:

- Initial reservoir pressure and temperature are 6,210 psia and 260°F at -2,894 m TVDSS.
- API gravity of the crude is approximately 36°.
- Bubblepoint pressure is 1,427 psia.
- Oil FVF at initial pressure is 1.35 RB/STB.
- GOR is approximately 325 SCF/STB.

A probabilistic spreadsheet model was constructed to calculate 1P, 2P, and 3P OOIP and gross (100 percent) technically recoverable oil volumes associated with reserves. GRV was input as a lognormal distribution with P90 input values based on NSAI mapping and P50 input values based on the average of NSAI and Energean mapping of the A Reservoir to an OWC of -2,945 m TVDSS. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions with minimum and most likely values based on NSAI petrophysical evaluation. However, maximum values also incorporated the Energean petrophysical assessment. Oil FVF was also modeled as a triangular distribution with input values based on NSAI PVT work previously described. Recovery factors are modeled as triangular distributions and based on dynamic modeling results.

To improve characterization of Epsilon future performance, fully independent static and dynamic models were built. We started with internal mapping of the A1 and A2 Reservoirs modified from provided seismic depth mapping. We then proceeded with 3-D property modeling using sequential Gaussian simulation constrained to E-1 logs. Next, we defined relative permeability and capillary pressure curves as well as vertical-to-horizontal permeability ratios based on our review of routine and special core analysis. Finally, we calibrated three different models by matching five months of production and flowing wellhead pressures from EA-1H. History matches of these three models, regarded as low side, base case, and high side matches, were achieved with multiple combinations of reservoir permeabilities and well skin factors. The good quality of the pressure history matches is shown in Figure 3.6.6.

Epsilon Field will have a phased development plan. The first phase will consist of three extended-reach wells drilled with the Jupiter rig from the Prinos B platform. It will take approximately five months to drill these wells starting in March 2018. Completion of these wells will be delayed until the 15-well-slot Lambda platform is completed in March 2019. These three wells will be completed and put on production starting in late March 2019. The oil rates in each producer will be limited to 1,000 BOPD, and bottomhole pressures will be kept above 1,700 psia to prevent asphaltene precipitation. Well performance will be closely

monitored and leveraged to refine estimates of oil-in-place and reservoir drive mechanisms. The second phase will be optimized based on these findings. If a low side oil-in-place scenario is found, the second phase will consist of only four additional producers and three water injector conversions. If a base case or high side oil-in-place is confirmed, the second phase will consist of six additional producers and five water injector conversions. Regardless of the subsurface scenario, all second-phase producers will be multilaterals with two 400-m sections drilled from the Lambda platform starting in July 2019. In addition, water injection will start in 2020 as needed to maintain reservoir pressure above the asphaltene precipitation region.

Using the three history-matched models and appropriate Epsilon Field development plan given the subsurface scenario, recovery factors were forecast. Low side, base case, and high side recovery factors were estimated to be 27.0, 42.5, and 55.0 percent, respectively.

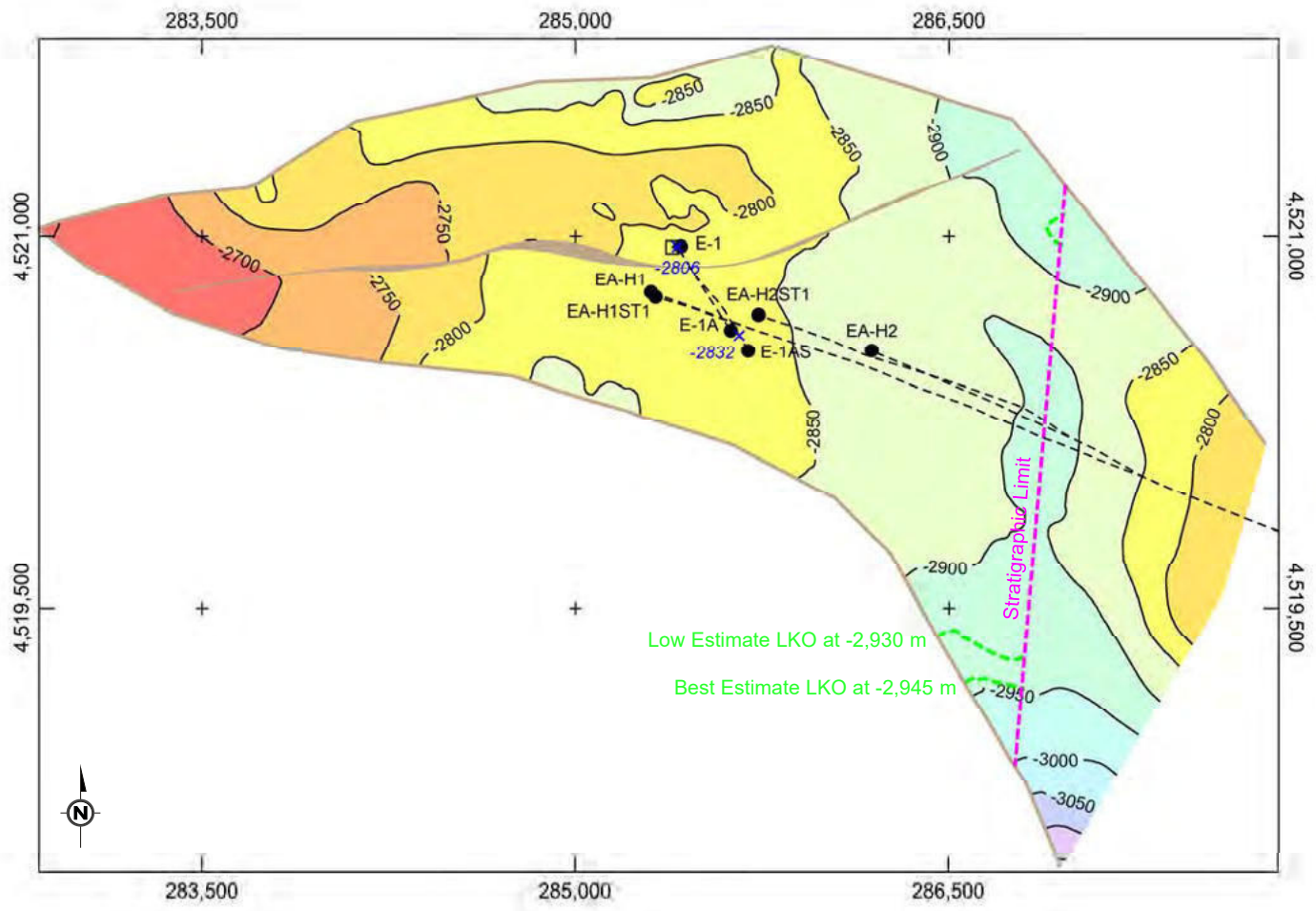
All volumetric input parameters for Epsilon Field are summarized in Figure 3.6.7. The resulting OOIP and gross (100 percent) technically recoverable volumes calculated in the probabilistic models are summarized in Figure 3.6.8.

Daily production forecasts for the reserves are shown by reserves category in Figure 3.6.9. Associated gas volumes are based on a field-processed GOR of 291 SCF/STB, as detailed in the Economics section of the Executive Summary.

3.5.3 RESOURCES DETERMINATION

Contingent resources are estimated for Epsilon Field based on additional recovery of up to 50 percent. These contingent resources are incremental to the 3P EUR of 24.6 MMBBL of oil. 1C, 2C, and 3C technically recoverable volumes are estimated at 0.0, 0.1, and 3.7 MMBBL of oil, respectively. Associated gas volumes are based on an expected processed field GOR of 291 SCF/STB, as detailed in the Economics section of the Executive Summary.

The potential discussed earlier for the deeper B and C Reservoirs was not evaluated as part of this report because its drilling as part of the early development drilling activities will shortly resolve its status.



Epsilon Field
Offshore Greece

Depth Structure
Top A1 Reservoir

Contour Interval: 50 m

SCALE IN METERS
0 250 500 750 1,000

Figure 3.6.1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

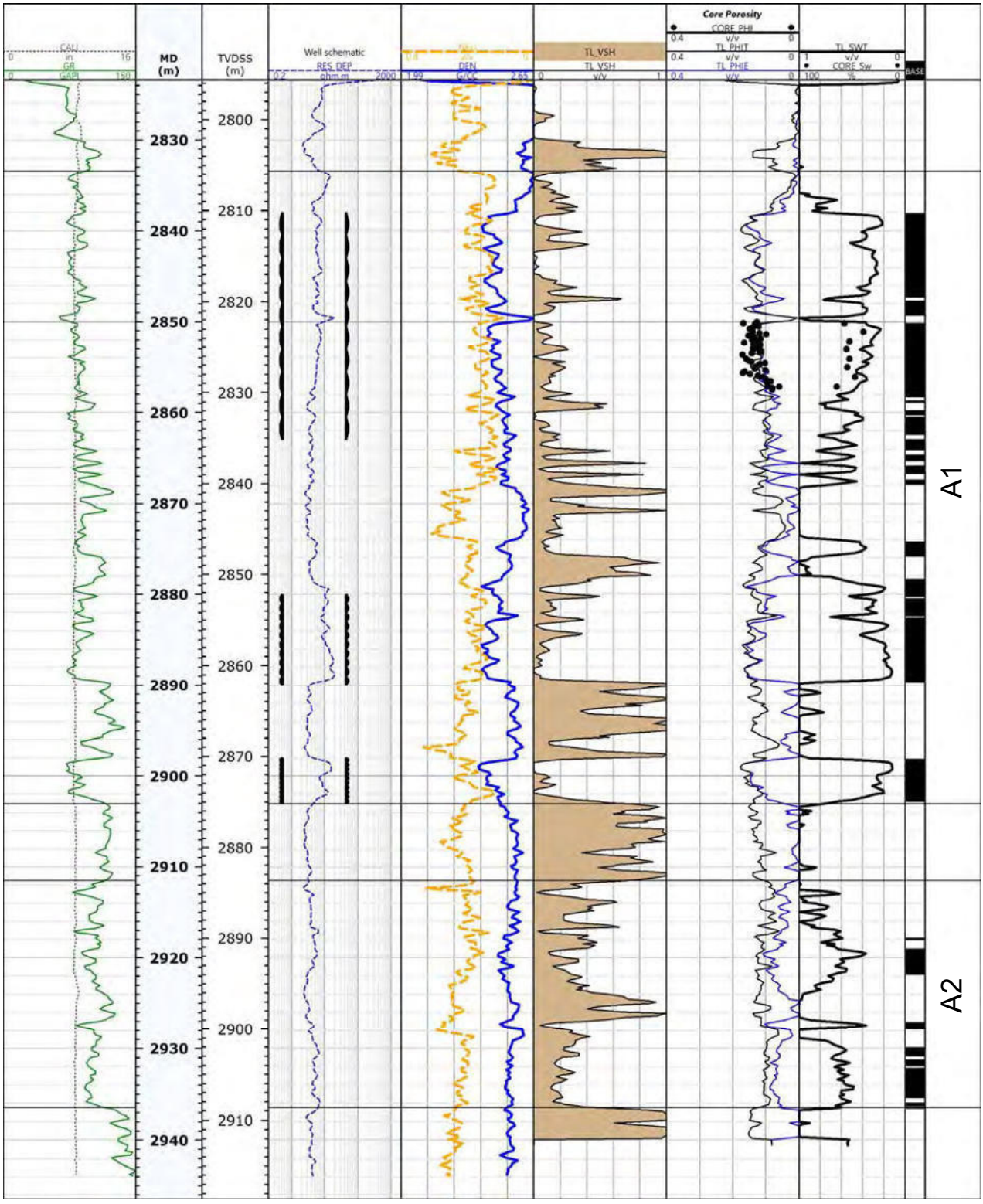
GROSS ROCK VOLUME BASIS
EPSILON FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	Best Estimate Case	Distribution Type
A1	1P	NSAI mapping based on LKO at -2,930 m TVDSS	Average of Energean and NSAI mapping with LKO at -2,945 m TVDSS to stratigraphic limit	Lognormal
A2	1P	NSAI mapping based on LKO at -2,930 m TVDSS	Average of Energean and NSAI mapping with LKO at -2,945 m TVDSS to stratigraphic limit	Lognormal

Figure 3.6.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

E-1 Well
Epsilon Field
Offshore Greece



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3.6.3

PETROPHYSICAL SUMMARY
EPSILON FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

						Low Estimate Case			Best Estimate Case			High Estimate Case		
	Depth (m MD)		Depth (m TVDSS)		Gross Interval	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation
Well/Reservoir	Top	Base	Top	Base	(m)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)
E-1														
A1	2,833	2,903	-2,806	-2,875	69.5	39.1	0.14	0.35	40.5	0.13	0.33	41.3	0.13	0.31
A2	2,912	2,937	-2,884	-2,909	25.0	5.2	0.11	0.56	8.3	0.11	0.55	10.6	0.11	0.51

Figure 3.6.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TEST DATA
EPSILON FIELD, OFFSHORE GREECE

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Duration Draw-Down/Build-Up (hour)	Oil Rate Avg (BOPD)	GOR (SCF/STB)	Gravity (°API)	Comment
E-1	1	2,880	2,890	6.5/20, 7.5/24	576	N/A	N/A	Two flow/buildup sequences. Reservoir pressure estimated at 6,100 psia.
E-1	2A	2,838	2,863	N/A	N/A	N/A	N/A	Aborted because of mechanical problems.
E-1	2B	2,838	2,863	4/1, 12/24	<100	N/A	N/A	Flow/buildup were dominated by wellbore storage.
E-1	2C	2,838	2,836	4/18.5	130 to 340	N/A	N/A	Acidization doubled production.
E-1AS	4A	3,040	3,046	3/1, 6.5/16, 9/67	600 to 1,000	N/A	N/A	Permeability estimated at 5.4 mD.
E-1AS	4B	3,040	3,046	N/A	862	N/A	N/A	Similar rates as before unsuccesful fracking attempt.

Figure 3.6.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

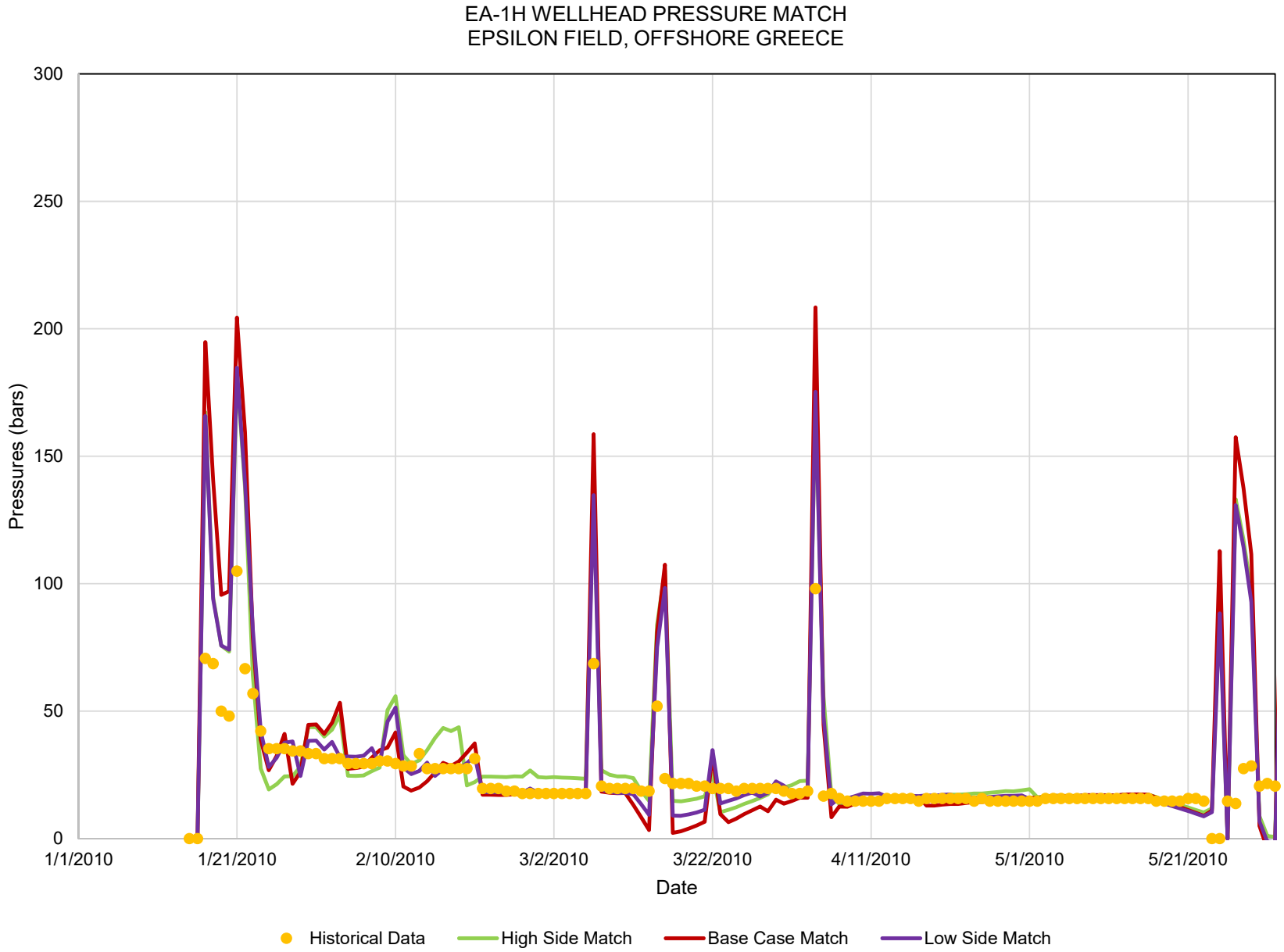


Figure 3.6.6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH OIL RESERVES
EPSILON FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category[1]	Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
		P90	P50	P10	Min	Most Likely	Max	Min	Most Likely	Max
A1	1P	108,364	122,225	N/A	0.56	0.58	0.69	0.117	0.120	0.123
A2	1P	47,021	63,695	N/A	0.21	0.33	0.42	0.077	0.080	0.090

Reservoir	Category[1]	Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
		Min	Most Likely	Max	Min	Most Likely	Max	Min	Most Likely	Max
A1	1P	0.73	0.76	0.79	1.33	1.35	1.37	0.270	0.425	0.550
A2	1P	0.56	0.61	0.73	1.33	1.35	1.37	0.270	0.425	0.550

[1] For reservoirs categorized as 1P, we have estimated 1P, 2P, and 3P technically recoverable volumes associated with reserves.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH OIL RESERVES
EPSILON FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1P	2P	3P	1P	2P	3P	1P	2P	3P
A1	33.6	39.0	45.2	12.0	16.2	21.1	36	41	47
A2	4.0	6.1	9.0	1.5	2.5	4.1	36	41	46
Arithmetic Sum[3]	37.6	45.1	54.2	13.4	18.7	25.2	36	41	46
Probabilistic Sum	38.9	45.3	52.6	13.9	18.8	24.6	36	42	47

(1) Technically recoverable volumes associated with reserves are prior to application of economics. The portion of the volumes that are economic are classified as reserves.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

(3) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF DAILY PRODUCTION RATES FOR RESERVES (BARRELS/DAY)
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
EPSILON FIELD, OFFSHORE GREECE

PERIOD ENDING	PROVED (1P) UNDEVELOPED	PROVED + PROBABLE (2P) UNDEVELOPED	PROVED + PROBABLE + POSSIBLE (3P) UNDEVELOPED
12-31-2017	0	0	0
12-31-2018	0	0	0
12-31-2019	2,607	2,607	2,607
12-31-2020	4,275	5,324	6,264
12-31-2021	2,999	4,941	4,966
12-31-2022	2,998	4,997	4,997
12-31-2023	2,998	4,997	4,997
12-31-2024	2,998	4,907	4,997
12-31-2025	2,668	3,898	4,937
12-31-2026	2,016	2,474	4,445
12-31-2027	1,999	2,964	3,292
12-31-2028	1,999	2,991	2,817
12-31-2029	1,999	2,717	2,998
12-31-2030	1,973	2,401	2,994
12-31-2031	1,674	1,906	2,802
12-31-2032	1,409	1,524	2,573
12-31-2033	995	926	2,341
12-31-2034	0	705	1,976

Figure 3.6.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

PRINOS NORTH FIELD

TECHNICAL DISCUSSION
PRINOS NORTH FIELD
OFFSHORE GREECE

4.1 OVERVIEW

Prinos North Field is located approximately 9 km northwest of Thasos Island and 15 km south of the Greek coast in a water depth of approximately 25 m. Figure 1.6.1 shows a location map of the area.

In 1992, the PN-2 discovery well was drilled and found oil on water in the main structure of the field. Three development wells have subsequently been drilled: PNA-H1, PNA-H2, and PNA-H3. These wells are either horizontal or high-angle wells, and the well paths are or have sidetracks. Production began in 1996 from the PNA-H1. Between 2004 and 2009, production ceased as a result of the unsuccessful sidetracking in PNA-H1 and PNA-H2. The production was only reinstated with the drilling of PNA-H3 in 2009. As of October 31, 2017, there was one well producing in the field at a rate of 159 BOPD. An updip horizontal well, PNA-H4, is scheduled to come on production in April 2018.

We have estimated reserves and contingent resources for the Top Prinos Group (TPG) Reservoir in Prinos North Field and contingent resources for a zone stratigraphically deeper than the Prinos Group referred to as the Delta Reservoir and Discovery.

4.1.1 RESERVES

We estimate the gross (100 percent) reserves for the TPG Reservoir of Prinos North Field, as of October 31, 2017, to be:

	Gross (100%) Reserves	
Category	Oil (MMBBL)	Sales Gas (BCF)
Proved Developed	0.1	0.0
Proved Undeveloped	2.1	0.1
Proved (1P)	2.2	0.1
Probable	1.1	0.1
Proved + Probable (2P)	3.3	0.3
Possible	1.1	0.1
Proved + Probable + Possible (3P)	4.4	0.4

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil volumes are expressed in MMBBL; a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in BCF at standard temperature and pressure bases.

4.1.2 CONTINGENT RESOURCES

The contingent resources shown in this report for the TPG Reservoir in Prinos North Field are contingent upon improved economic parameters and improved recovery rates. The contingent resources shown in this report for Delta Discovery are contingent upon creation of a development plan and commitment from Energean to develop the properties.

We estimate the unrisked gross (100 percent) contingent resources for Prinos North Field and Delta Discovery, as of October 31, 2017, to be:

	Unrisked Gross (100%) Contingent Resources	
Category	Oil (MMBBL)	Sales Gas (BCF)
TPG Reservoir		
Low Estimate (1C)	1.1	0.2
Best Estimate (2C)	2.4	0.4
High Estimate (3C)	3.8	0.6
Delta Discovery		
Low Estimate (1C)	0.7	0.0
Best Estimate (2C)	1.6	0.0
High Estimate (3C)	2.8	0.0
Total		
Low Estimate (1C)	1.8	0.2
Best Estimate (2C)	3.9	0.4
High Estimate (3C)	6.6	0.6

Totals may not add because of rounding.

The oil volumes shown include crude oil only.

4.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation in addition to the data listed in the Executive Summary are listed below:

- Petrophysical data for the PN-2 well including CPI logs and associated reports as well as conventional core data and associated routine core analysis
- MDT, repeat formation test (RFT), and express pressure test (XPT) pressure and temperature data
- Available flowing well test data for new discovery wells

4.3 GEOLOGIC SUMMARY

4.3.1 OVERVIEW

Prinos North Field is located in the Prinos Basin, offshore Greece, in the northern Aegean Sea between mainland Greece and Thasos Island. The field is located a few kilometers to the north and northeast of Prinos and Epsilon Fields, respectively, upthrown on the previously discussed major listric fault that sets up those fields. While the productive interval is also stacked Miocene age turbiditic sandstones of the Prinos Group, the reservoir does not maintain the same alphabetic nomenclature as the Prinos and Epsilon Fields. Instead, it is simply referred to as "Top Prinos Group".

Below the producing interval, a deeper sand interval of the Prinos Group called the Delta Reservoir tested oil.

4.3.2 PRINOS NORTH FIELD

4.3.2.1 Top Prinos Group

Prinos North Field is a four-way, dip-closed anticline bounded to the southwest by the major listric fault discussed previously and to the east, west, and north by some minor normal faulting. The western normal faults dip away from the anticline and trend northeast to southwest. The main fault block is being produced by the PNA-H3ST2 horizontal development well where the TPG Reservoir can be found at approximately -2,050 m TVDSS. A depth structure map is shown on Figure 4.6.1.

The TPG Reservoir has a net thickness of 25.6 m in the PN-2 well. Fieldwide sand distribution is not fully understood since there are few penetrations; however, horizontal drilling successes seem to indicate good reservoir continuity throughout Prinos North. Based on our independent petrophysical analysis, the PN-2 well has a best estimate NTG of 76 percent above the contact and an average effective porosity of 18 percent and average water saturation of 32 percent. As in Epsilon Field, the reservoir quality is slightly lower than Prinos Field. Again, it is worthwhile to note that since the averages are based on one well, they may not be fully representative, and in fact, cumulative production suggests better rock quality away from the PN-2 wellbore. A stratigraphic column is shown on Figure 1.6.2.

An OWC of -2,156 m TVDSS is the basis for the best case volumetric calculation in Prinos North Field. This contact is derived from well log analysis. Low and high cases were determined by ranging the GRV for this case by 10 percent. A table showing the basis for the GRV calculation is shown on Figure 4.6.2.

The TPG Reservoir is producing, and volumes are classified as reserves.

4.3.3 DELTA DISCOVERY

4.3.3.1 Delta Reservoir

The PN-2 well penetrated a deeper sand interval referred to as the Delta Reservoir and Discovery. This sand was cored and tested oil. The structural feature that traps this oil is bounded by the same faults as the shallower Prinos North Field and has a similar anticlinal configuration. A depth structure map is shown on Figure 4.6.3.

Petrophysical analysis performed over this interval indicates an OWC at -2,327 m TVDSS, which was used for the volumetric calculation. The Delta Reservoir has a best estimate NTG of 66 percent, average effective porosity of 17 percent, and water saturation of 50 percent in the PN-2 well. A table showing the basis for the GRV calculation is shown on Figure 4.6.4.

Volumes for the Delta Discovery are classified as contingent resources.

4.4 PETROPHYSICAL SUMMARY

The petrophysical evaluation methodology described in Section 1.5.1 of the Executive Summary was used for Prinos North Field and Delta Discovery. The interpreted well logs for the PN-2 well are shown on Figures 4.6.5 and 4.6.6. The petrophysical summary table for the TPG and Delta Reservoirs is shown on Figure 4.6.7.

4.5 RESERVOIR ENGINEERING SUMMARY

4.5.1 DEVELOPMENT HISTORY

Following the drilling of the PN-2 discovery well in 1994, Prinos North Field was developed by an extended-reach well (PNA-H1) from the Prinos platform in 1996. The well produced sour oil of 21° API at a rate of over 3,000 BOPD before going on decline. The field was shut in during 1999 and handed back to the Greek State because of low production and prices. In December 1999, production was resumed and continued until 2004 when the well was shut in because of high water production. An unsuccessful attempt was made to sidetrack the well as the PNA-H2 in June 2004. The well was later successfully sidetracked as the PNA-H3 well and returned to production in July 2009. Cumulative oil production from Prinos North is 4.15 MMBBL as of October 31, 2017.

4.5.2 RESERVES DETERMINATION

The oil from Prinos North Field is an undersaturated sour crude with a high wax and asphaltene content. The crude contains about 7 percent sulfur, and solution gas contains approximately 30 percent H_2S. The field GOR is approximately 300 SCF/STB.

A new horizontal well, PNA-H4, is planned to be drilled at the end of 2017, updip of the current producing well to capture additional attic reserves in the TPG Reservoir. DCA was used to estimate 1P, 2P, and 3P producing reserves from the existing PNA-H3 well, and volumetric estimates were used to estimate the 1P, 2P, and 3P reserves for the new PNA-H4 attic location.

A probabilistic spreadsheet model was constructed to calculate 1P, 2P, and 3P OOIP and gross (100 percent) technically recoverable oil volumes associated with reserves in the TPG Reservoir. GRV for the TPG Reservoir was input as a normal distribution with P90 and 10 percent confidence level (P10) input values based on the low and high estimate cases discussed earlier. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions with input values based on NSAI petrophysical evaluation. Oil FVF and recovery factors were also modeled as triangular distributions with input values based on PN-2 DST-2 PVT analysis and historical performance data, respectively. A most likely recovery factor of 35 percent is based on the EUR from the PNA-H3 for the downstructure reservoir volumes. Minimum and maximum recovery factors were estimated at 30 and 40 percent, respectively.

Recoverable volumes for the planned PNA-H4 attic well were estimated by reducing the recoverable 1P, 2P, and 3P volumes of 7.2, 8.5, and 10.0 MMBBL of oil from the probabilistic model by the estimated EUR for the PNA-H3 well and a factor for undrained attic volume updip of the new well. This factor is 20, 15, and 10 percent in the 1P, 2P, and 3P cases, respectively. The resulting 1P, 2P, and 3P technically recoverable volumes for the PNA-H4 well are 2.4, 3.6, and 5.1 MMBBL of oil, respectively.

All probabilistic volumetric input parameters for Prinos North Field reserves are summarized in Figure 4.6.8. The resulting OOIP and gross (100 percent) technically recoverable volumes associated with reserves calculated in the probabilistic model are summarized in Figure 4.6.9. Daily production forecasts for the reserves are shown by reserves category in Figure 4.6.10

The PNA-H4 is planned to start drilling by the end of 2017. Production is forecast to begin in April 2018, with plateau rates being reached in 2 months at approximately 800 BOPD. The flowstreams account for field downtime, which is expected to be reduced to 2 percent by 2020. In the 1P case, downtime accounted for in the flowstreams is 10 percent through the end of 2018, 5 percent in 2019, and 2 percent in 2020. In the 2P case, downtime is 5 percent through the end of 2018, 4 percent in 2019, and 2 percent in 2020. In the 3P case, downtime is 2 percent through the end of 2020. Associated gas volumes are based on a field-processed GOR of 148 SCF/STB, as detailed in the Economics section of the Executive Summary.

4.5.3 RESOURCES DETERMINATION

Contingent resources are estimated for the Prinos North TPG Reservoir based on additional recovery up to 45 percent. These contingent resources are incremental to the 3P EUR of 10.0 MMBBL of oil. 1C, 2C, and 3C technically recoverable oil volumes are estimated at 1.1, 2.4, and 3.8 MMBBL, respectively. Associated gas volumes are based on an expected field-processed GOR of 148 SCF/STB, as detailed in the Economics section of the Executive Summary.

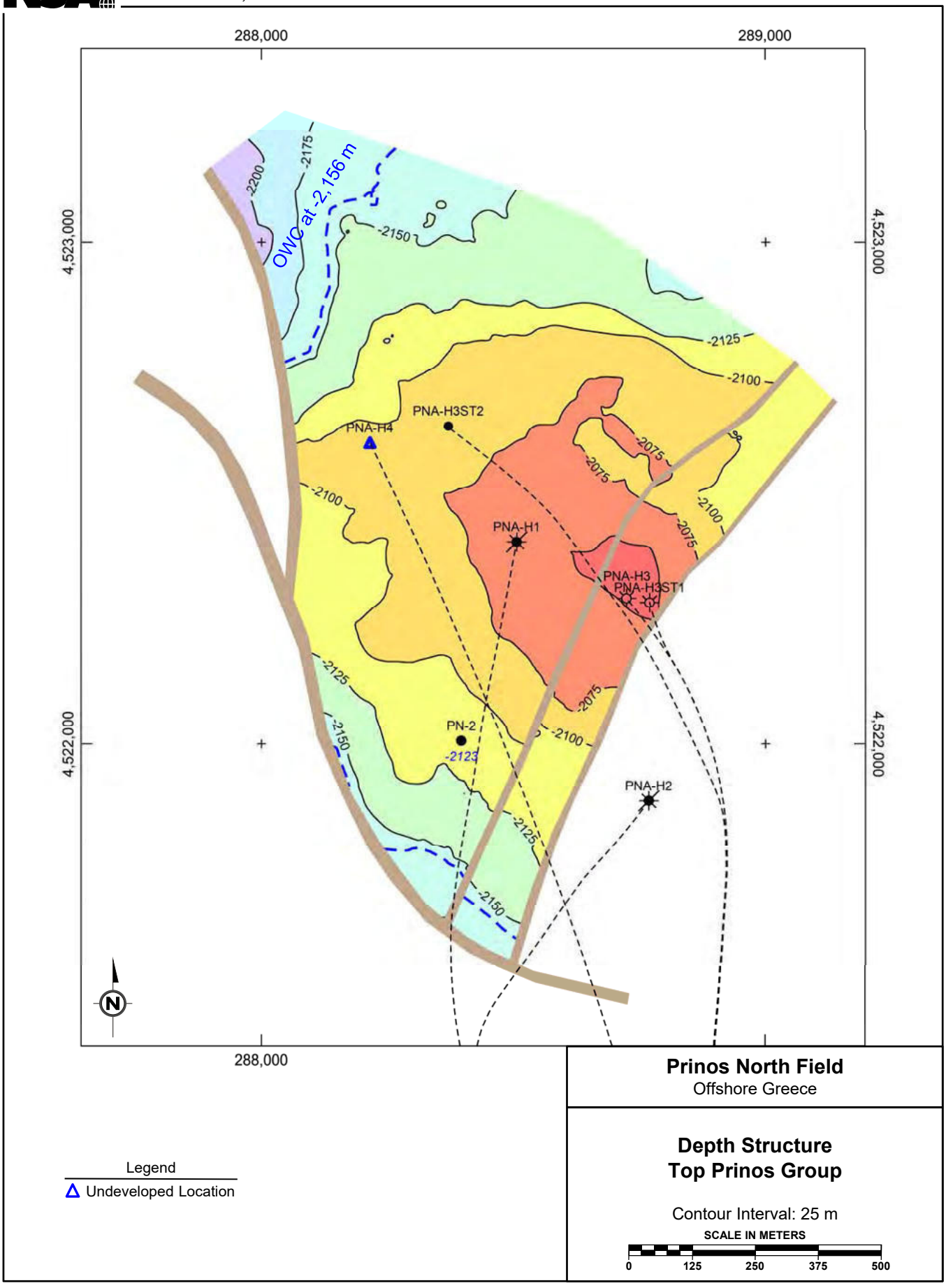
Contingent resources are also estimated for the Delta Discovery. One interval was tested in the PN-2 well for approximately 8 hours. Test data for the Delta Discovery are shown on Figure 4.6.11.

Estimated fluid and reservoir properties for the Delta Discovery are based on the PN-2 PVT data and are summarized below:

- Initial reservoir pressure ranges from 5,145 to 5,185 psia.
- API gravity of the crude ranges from 21 to 23°.
- Initial reservoir GOR ranges from 200 to 250 SCF/STB.
- Oil FVF is approximately 1.16 to 1.20 RB/STB.

A probabilistic spreadsheet model was constructed to calculate 1C, 2C, and 3C OOIP and gross (100 percent) technically recoverable oil volumes associated with Delta Discovery. GRV was input as a normal distribution with 99 percent confidence level (P99) and P10 input values. The P99 input is based on the NSAI GRV assuming an OWC at -2,327 m TVDSS. The P10 input value incorporates an alternate interpretation where the reservoir quality diminishes near the base of the reservoir, resulting in high water saturations, and the entire block volume is used. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions and are based on NSAI petrophysical evaluation. Oil FVF and recovery factors were also modeled as triangular distributions. Oil FVF is based on the NSAI interpretation of the PVT data, and recovery factors are based on analogy to similar reservoirs in the area.

All volumetric input parameters for Delta Discovery are summarized in Figure 4.6.12. The resulting OOIP and gross (100 percent) technically recoverable volumes associated with contingent oil resources calculated in the probabilistic model are summarized in Figure 4.6.13. Because economic analysis has not been performed on these volumes, contingent oil resources for Delta Discovery are equal to the technically recoverable volumes shown on Figure 4.6.13.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

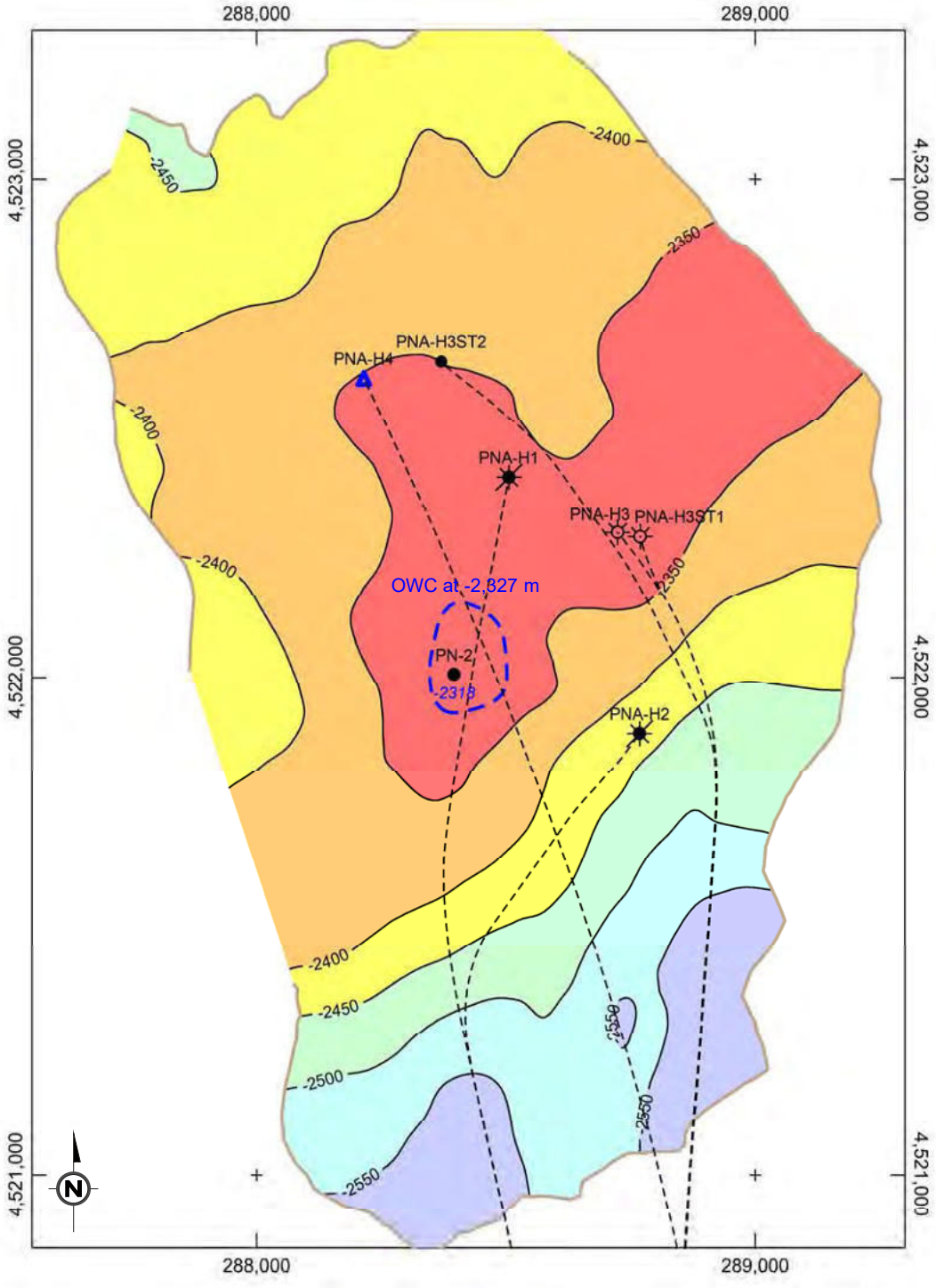
Figure 4.6.1

GROSS ROCK VOLUME BASIS
PRINOS NORTH FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	Best Estimate Case	High Estimate Case	Distribution Type
Top Prinos Group	1P	Best estimate -10%	OWC at -2,156 m TVDSS	Best estimate +10%	Normal

Figure 4.6.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.



Delta Discovery
Offshore Greece

Depth Structure
Top Delta Reservoir

Contour Interval: 50 m

SCALE IN METERS
0 125 250 375 500

Legend
Δ Undeveloped Location

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4.6.3

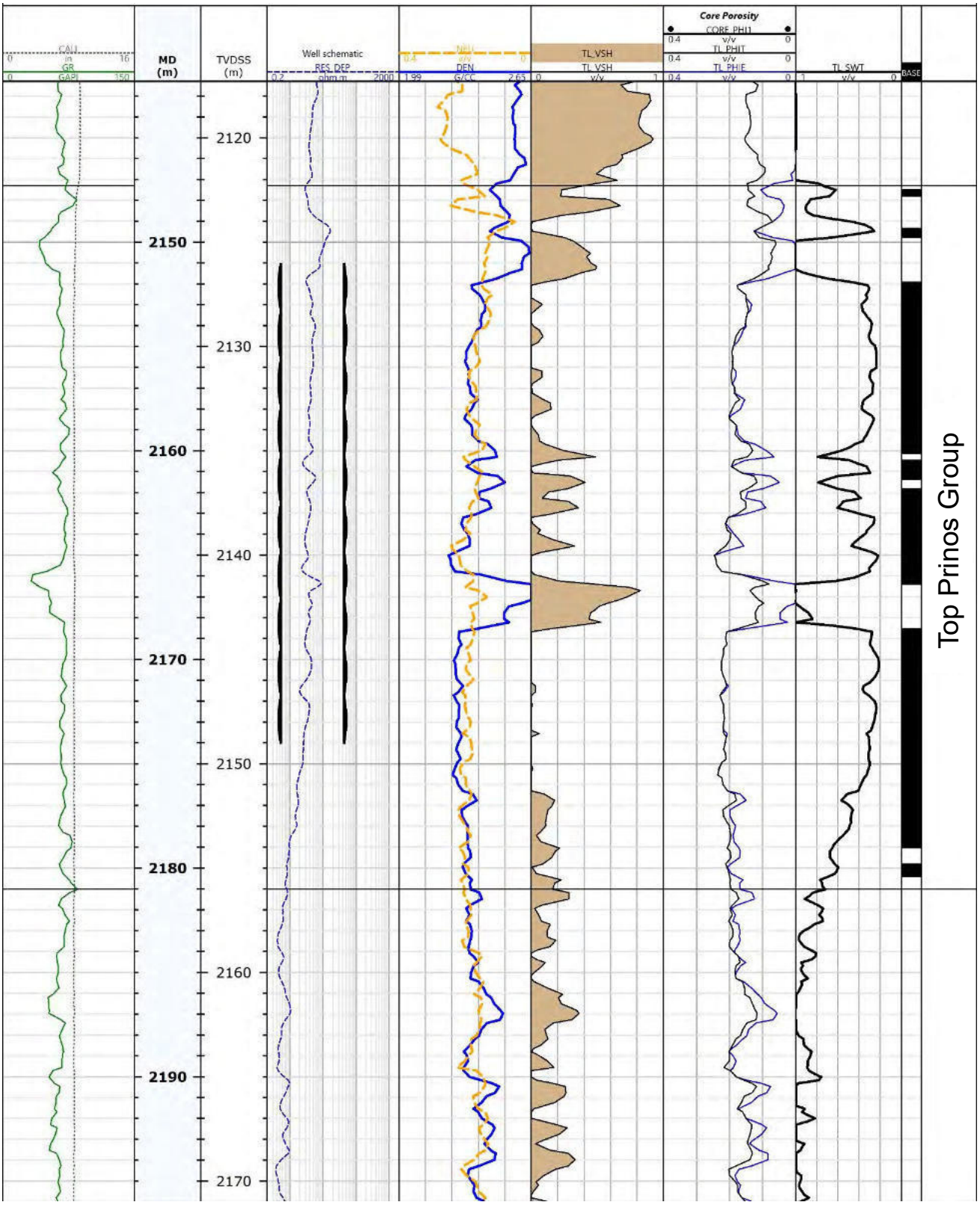
GROSS ROCK VOLUME BASIS
DELTA DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	High Estimate Case	Distribution Type
Delta	1C	OWC at -2,327 m TVDSS	Full block	Lognormal

Figure 4.6.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

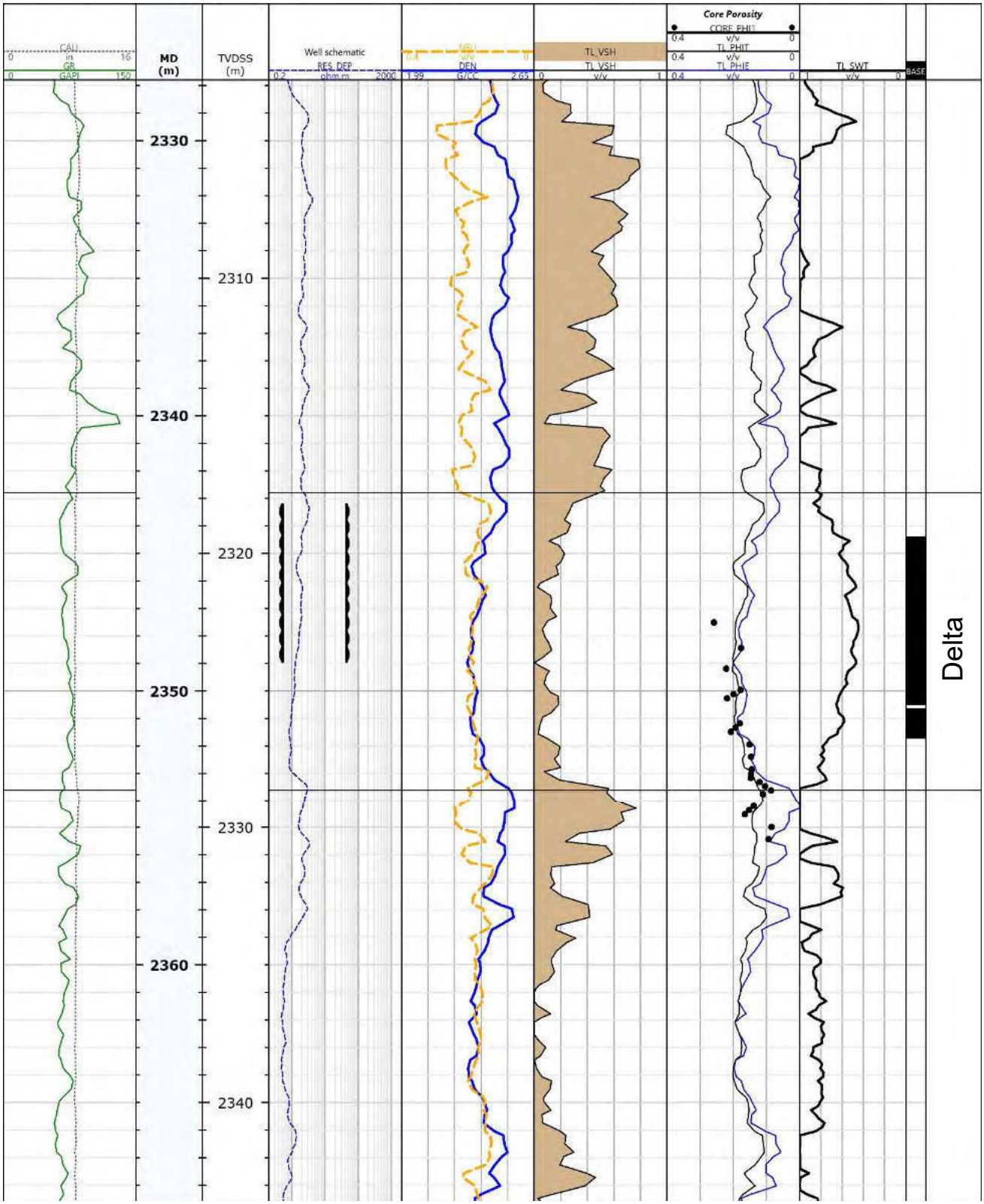
PN-2 Well
Top Prinos Group Reservoir, Prinos North Field
Offshore Greece



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4.6.5

PN-2 Well
Delta Reservoir, Delta Discovery
Offshore Greece



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4.6.6

PETROPHYSICAL SUMMARY
PRINOS NORTH FIELD AND DELTA DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

						Low Estimate Case			Best Estimate Case			High Estimate Case		
	Depth (m MD)		Depth (m TVDSS)		Gross Interval	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation
Well/Reservoir	Top	Base	Top	Base	(m)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)
PN-2														
Top Prinos Group	2,147	2,181	-2,122	-2,156	33.7	24.4	0.19	0.32	25.6	0.18	0.32	27.3	0.18	0.31
Delta	2,343	2,354	-2,318	-2,329	10.8	5.9	0.17	0.51	7.2	0.17	0.50	7.9	0.16	0.47

Figure 4.6.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH OIL RESERVES
PRINOS NORTH FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category[1]	Gross Rock Volume (Acre-Feet) P90	P50	P10	Net-to-Gross Ratio (Decimal) Min	Most Likely	Max	Porosity (Decimal) Min	Most Likely	Max
Top Prinos Group	1P	36,436	40,484	44,532	0.72	0.76	0.81	0.17	0.18	0.19

Reservoir	Category[1]	Hydrocarbon Saturation (Decimal) Min	Most Likely	Max	Formation Volume Factor (RB/STB) Min	Most Likely	Max	Recovery Factor (Decimal) Min	Most Likely	Max
Top Prinos Group	1P	0.65	0.68	0.70	1.15	1.20	1.25	0.30	0.35	0.40

[1] For reservoirs categorized as 1P, we have estimated 1P, 2P, and 3P technically recoverable volumes associated with reserves.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH OIL RESERVES
PRINOS NORTH FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1P	2P	3P	1P	2P	3P	1P	2P	3P
Top Prinos Group	21.4	24.3	27.5	7.2	8.5	10.0	33	35	36

(1) Technically recoverable volumes associated with reserves are prior to application of economics. The portion of the volumes that are economic are classified as reserves.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF DAILY PRODUCTION RATES FOR RESERVES (BARRELS/DAY)
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
PRINOS NORTH FIELD, OFFSHORE GREECE

PERIOD ENDING	PROVED (1P)			PROVED + PROBABLE (2P)			PROVED + PROBABLE + POSSIBLE (3P)		
	DEVELOPED	UNDEVELOPED	TOTAL	DEVELOPED	UNDEVELOPED	TOTAL	DEVELOPED	UNDEVELOPED	TOTAL
12-31-2017	157	0	157	182	0	182	204	0	204
12-31-2018	123	473	596	153	499	652	177	515	691
12-31-2019	79	750	828	103	757	861	129	773	903
12-31-2020	49	773	822	68	773	842	90	773	864
12-31-2021	10	816	826	46	800	846	65	793	858
12-31-2022	0	785	785	8	800	808	45	793	839
12-31-2023	0	511	511	0	800	800	13	793	807
12-31-2024	0	349	349	0	800	800	0	793	793
12-31-2025	0	265	265	0	800	800	0	793	793
12-31-2026	0	214	214	0	649	649	0	793	793
12-31-2027	0	179	179	0	444	444	0	793	793
12-31-2028	0	154	154	0	338	338	0	793	793
12-31-2029	0	136	136	0	273	273	0	793	793
12-31-2030	0	121	121	0	229	229	0	732	732
12-31-2031	0	109	109	0	197	197	0	534	534
12-31-2032	0	99	99	0	173	173	0	414	414
12-31-2033	0	91	91	0	154	154	0	338	338
12-31-2034	0	0	0	0	139	139	0	285	285

Figure 4.6.10

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TEST DATA
DELTA DISCOVERY, OFFSHORE GREECE

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Zone	Duration (hour)	Choke (inch)	Oil Rate Max (BOPD)	Oil Rate Avg (BOPD)	S_w (%)	GOR (SCF/STB)	FWHP (psig)	Gravity (°API)	Comment
PN-2	DST-1	2,343	2,349	Delta	8	32/64	422	355	N/A	N/A	N/A	17.4	2.3 cp at reservoir conditions

Figure 4.6.11

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH CONTINGENT OIL RESOURCES
DELTA DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
						Most			Most	
Reservoir	Category[1]	P99	P50	P10	Min	Likely	Max	Min	Likely	Max
Delta	1C	118	N/A	22,470	0.55	0.66	0.85	0.150	0.166	0.180

		Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
			Most			Most			Most	
Reservoir	Category[1]	Min	Likely	Max	Min	Likely	Max	Min	Likely	Max
Delta	1C	0.45	0.50	0.55	1.16	1.18	1.20	0.20	0.30	0.40

(1) For reservoirs categorized as 1C, we have estimated 1C, 2C, and 3C technically recoverable volumes associated with contingent resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH CONTINGENT OIL RESOURCES
DELTA DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1C	2C	3C	1C	2C	3C	1C	2C	3C
Delta	2.4	5.3	8.7	0.7	1.6	2.8	28	29	32

(1) Because economic analysis has not been performed on these volumes, contingent oil resources for Delta Reservoir are equal to the technically recoverable volumes shown.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ATHOS DISCOVERY

TECHNICAL DISCUSSION
ATHOS DISCOVERY
OFFSHORE GREECE

5.1 OVERVIEW

We have estimated the unrisked gross (100 percent) contingent oil resources, as of October 31, 2017, for the Athos Discovery located offshore Greece straddling the Prinos and South Kavala licenses. Figure 1.6.1 shows a location map of the area. The contingent resources shown in this report for the Athos Discovery are contingent upon creation of a development plan and commitment from Energean to develop the properties.

One well has been drilled in this discovery. The Athos-1 was drilled and tested in 1982 at rates up to 412 BOPD of clean, sweet oil.

We estimate the unrisked gross (100 percent) contingent oil resources for the Athos Discovery, as of October 31, 2017, to be:

Unrisked Gross (100%) Contingent Oil Resources (MMBBL)		
1C	2C	3C
1.6	2.4	3.5

The oil volumes shown include crude oil only. Oil volumes are expressed in MMBBL; a barrel is equivalent to 42 United States gallons.

5.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation in addition to the data listed in the Executive Summary are listed below:

- Top and base for the productive interval in the Athos-1 well
- Petrophysical report for the Athos-1 well

5.3 GEOPHYSICAL AND GEOLOGICAL SUMMARY

5.3.1 OVERVIEW

The Athos structure lies 9 km southwest of Prinos Field in the North Aegean Sea between mainland Greece and Thasos Island in a water depth of 52 m. The field was identified with seismic data and drilled in 1982 by the North Aegean Petroleum Company. The primary target was the sands enveloped in the evaporitic Middle and Lower Miocene section, which are gas-bearing in the nearby South Kavala Field. A stratigraphic column is shown on Figure 1.6.2. The Athos-1 well was also designed to test the deeper equivalent

reservoirs that are found productive in Prinos Field. The well was drilled to a measured depth of 2,842 m. Approximately 12 percent of the reservoir is outside of the Prinos and South Kavala license areas.

An open-hole test was performed in the interval from 2,574 to 2,666 m measured depth (MD). The interval consisted of thinly laminated sand and shale sequences that appeared to be fair to poor quality based on the open-hole logs. This interval could be a trap consisting of a combination of structural and stratigraphic elements. The reservoir is interpreted as being deposited on the distal edge of a turbidite fan complex in the Prinos Group. The Athos-1 well tested at an average of approximately 250 BOPD.

5.3.2 GEOLOGIC MAPPING

The interval tested in the Athos-1 consists of a series of very thinly laminated sand and shale sequences that are not well defined on the open-hole wireline logs. The 3-D seismic data quality is fair to poor, and bounding faults are difficult to confidently map. However, we have independently mapped a single seismic horizon that appears to correlate to the top of the oil-tested zone in the Athos-1 well. The depth structure map for Athos Reservoir is shown in Figure 5.6.1.

Even though the overall tested interval consists of numerous thin sand intervals, the quality of each individual sand package could be fair to good. The continuity of these individual sands remains uncertain. In our petrophysical analysis, we have estimated a relatively low NTG of 18 to 23 percent and a porosity ranging from 13 to 14 percent.

Our interpretation consists of a low case that includes only the open-hole tested interval from 2,574 to 2,666 m MD and is confined to faults or stratigraphic reservoir limits of approximately 780 on-lease acres. For the high case, we have assumed that the oil column extends to the same fault or stratigraphic limit but that the area is completely filled with 92 m of oil. A summary of the basis for the GRV calculations is provided in Figure 5.6.2.

5.4 PETROPHYSICAL SUMMARY

Independent petrophysical calculations were carried out using available well log data supplied by Energean. Shale volume estimates were made using the gamma ray, neutron porosity, and bulk density measurements. A nonlinear Stieber gamma ray shale volume estimate as well as a shale volume estimate derived from neutron and density porosity separation were both used in the petrophysical evaluation. Porosity was estimated from the shale-corrected bulk density and neutron porosity measurements. Resistivity measurements were not available for the evaluation, and water saturation estimates were not interpreted. A total porosity cutoff of 9 percent and a shale volume cutoff of 40 percent were used to generate petrophysical property estimates in net reservoir intervals. The interpreted well log for the Athos-1 well is shown in Figure 5.6.3. The petrophysical summary table for Athos Discovery is shown in Figure 5.6.4.

5.5 RESERVOIR ENGINEERING SUMMARY

One interval was tested in the Athos-1 well with two flow periods ranging from 11.5 to 12.5 hours. Test data for the Athos Discovery are shown on Figure 5.6.5.

Estimated fluid and reservoir properties for the Athos Discovery are summarized below:

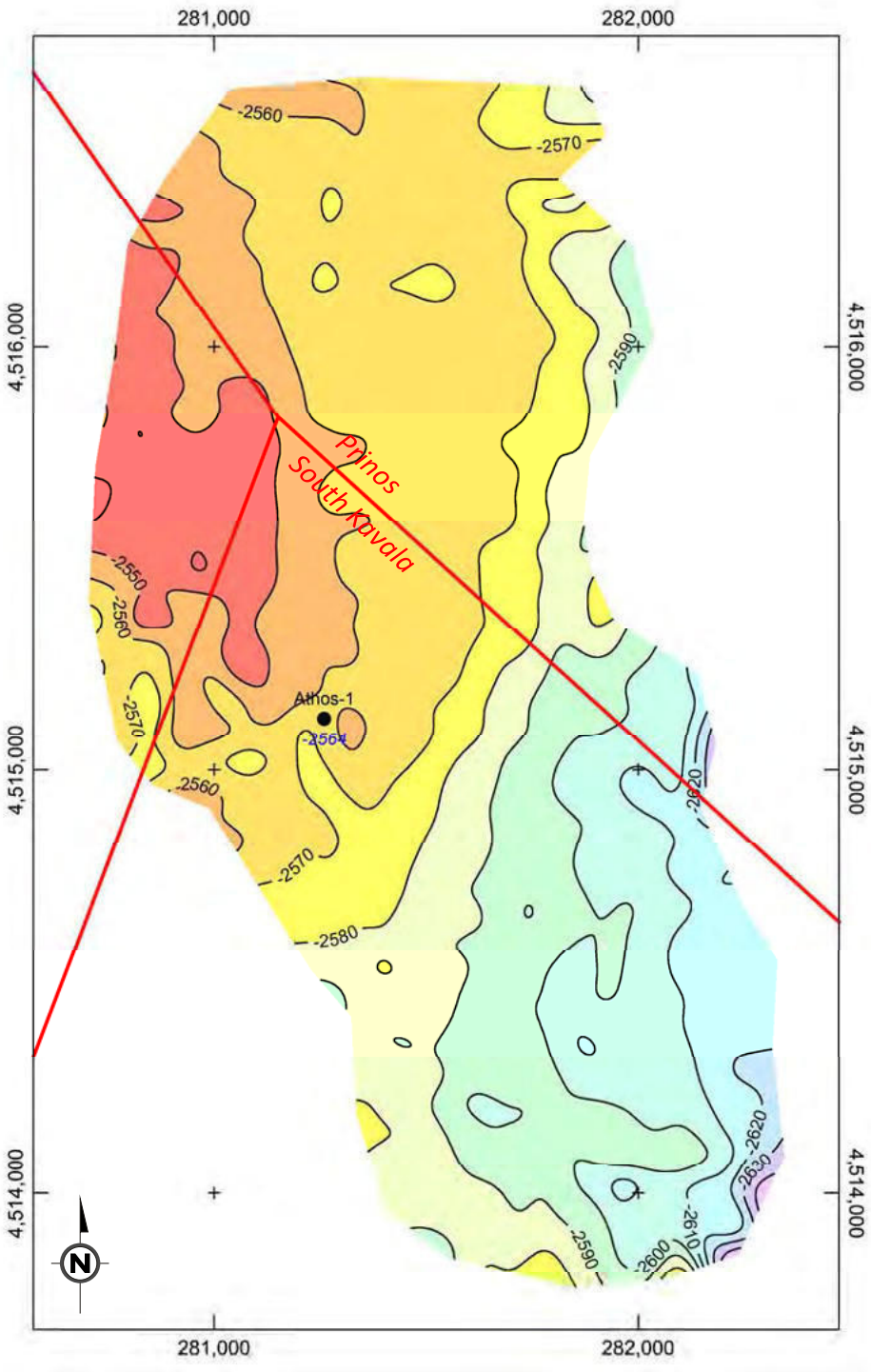
- Initial reservoir pressure ranges from 5,200 to 5,520 psia.

- API gravity of the crude ranges from 27 to 40°.
- Initial reservoir GOR ranges from 400 to 550 SCF/STB.
- Oil FVF is approximately 1.27 to 1.34 RB/STB.

5.5.1 PROBABILISTIC RESOURCES DETERMINATION

A probabilistic spreadsheet model was constructed to calculate 1C, 2C, and 3C OOIP and gross (100 percent) technically recoverable oil volumes associated with contingent oil resources for Athos Discovery. GRV was input as a lognormal distribution with P95 and P05 input values based on the low and high estimate cases discussed earlier. Volumes not on the Prinos or South Kavala license areas, which range from 11 to 12 percent of the GRV, have not been included in this evaluation. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions; NTG and porosity were based on NSAI petrophysical evaluation, while hydrocarbon saturation was based on saturations from analogous reservoirs. Oil FVF and recovery factors were also modeled as triangular distributions with input values based on available test data and analogy to similar reservoirs.

All volumetric input parameters are summarized in Figure 5.6.6. The resulting on-lease OOIP and gross (100 percent) technically recoverable volumes associated with contingent oil resources calculated in the probabilistic model are summarized in Figure 5.6.7. Because economic analysis has not been performed on these volumes, contingent oil resources for Athos Discovery are equal to the technically recoverable volumes shown on Figure 5.6.7.



Athos Discovery
Offshore Greece

Depth Structure
Top Athos Reservoir

Contour Interval: 10 m

SCALE IN METERS

0 250 500 750 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5.6.1

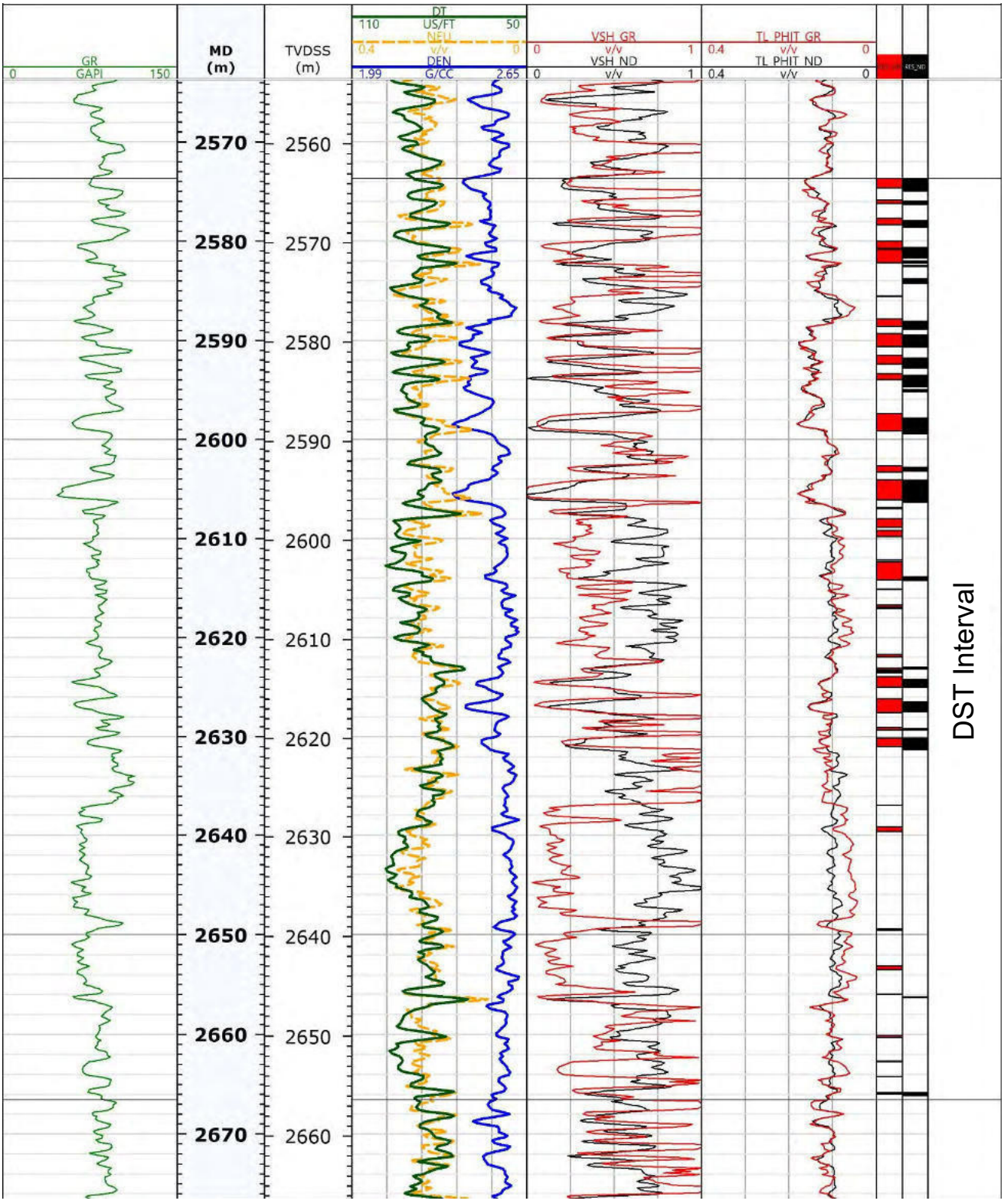
GROSS ROCK VOLUME BASIS
ATHOS DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	High Estimate Case	Distribution Type
Athos	1C	Base of the DST at -2,656 m TVDSS	Full block	Lognormal

Figure 5.6.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Athos-1 Well
Athos Discovery
Offshore Greece



Pay Flag: Gamma Ray V_{sh}
Pay Flag: Neutron-Density V_{sh}

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5.6.3

PETROPHYSICAL SUMMARY
ATHOS DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Depth (m MD)		Depth (m TVDSS)		Gross	Neutron-Density V_{sh}			Gamma Ray V_{sh}		
Reservoir	Top	Base	Top	Base	Interval (m)	Net Pay (m)	NTG (Decimal)	Porosity (Decimal)	Net Pay (m)	NTG (Decimal)	Porosity (Decimal)
Athos	2,574	2,667	-2,563	-2,656	92.9	16.5	0.18	0.14	21.5	0.23	0.13

Figure 5.6.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TEST DATA
ATHOS DISCOVERY, OFFSHORE GREECE

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Zone	Duration (hour)	Choke (inch)	Oil Rate Max (BOPD)	Oil Rate Avg (BOPD)	S_w (%)	GOR (SCF/STB)	FWHP (psig)	Gravity (°API)	CO_2 (%)	H_2S (ppm)	Comment
Athos-1	DST	2,574	2,666	Flow 1	12.5	28/64	412	270	50	N/A	165	N/A	N/A	N/A	Not stabilized; 25% oil and 25% mud
		2,574	2,666	Flow 2	11.5	32/64	>350	235	0	509	310	27.0	0	0	Reported clean, sweet oil

Figure 5.6.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH CONTINGENT OIL RESOURCES
ATHOS DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category[1]	On-Lease Gross Rock Volume (Acre-Feet) P95	P50	P05	Net-to-Gross Ratio (Decimal) Min	Most Likely	Max	Porosity (Decimal) Min	Most Likely	Max
Athos	1C	171,560	N/A	211,517	0.150	0.205	0.230	0.12	0.13	0.15

Reservoir	Category[1]	Hydrocarbon Saturation (Decimal) Min	Most Likely	Max	Formation Volume Factor (RB/STB) Min	Most Likely	Max	Recovery Factor (Decimal) Min	Most Likely	Max
Athos	1C	0.45	0.55	0.65	1.27	1.31	1.34	0.10	0.15	0.20

[1] For reservoirs categorized as 1C, we have estimated 1C, 2C, and 3C technically recoverable volumes associated with contingent resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ON-LEASE ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH CONTINGENT OIL RESOURCES
ATHOS DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1C	2C	3C	1C	2C	3C	1C	2C	3C
Athos	12.4	16.2	20.5	1.6	2.4	3.5	13	15	17

(1) Because economic analysis has not been performed on these volumes, contingent oil resources for Athos Discovery are equal to the technically recoverable volumes shown.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

KAZAVITI DISCOVERY

TECHNICAL DISCUSSION
KAZAVITI DISCOVERY
OFFSHORE GREECE

6.1 OVERVIEW

We have estimated the unrisked gross (100 percent) contingent oil resources, as of October 31, 2017, for Kazaviti Discovery located offshore Greece within the Prinos license area. Figure 1.6.1 shows a location map of the area. The contingent resources shown in this report for Kazaviti Discovery are contingent upon creation of a development plan and commitment from Energean to develop the properties.

Two wells have been drilled in this discovery. The P-4 well was drilled in 1976 and successfully tested in two intervals. The PA-36 well was drilled 2016 but was not tested.

We estimate the unrisked gross (100 percent) contingent oil resources for Kazaviti Discovery, as of October 31, 2017, to be:

Unrisked Gross (100%) Contingent Oil Resources (MMBBL)		
1C	2C	3C
0.4	0.9	1.2

The oil volumes shown include crude oil only. Oil volumes are expressed in MMBBL; a barrel is equivalent to 42 United States gallons.

6.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation in addition to the data listed in the Executive Summary are listed below:

- Tops and bases for the productive intervals in the P-4 and PA-36 wells
- A petrophysical report for the P-4 and PA-36 wells

6.3 GEOPHYSICAL AND GEOLOGICAL SUMMARY

6.3.1 OVERVIEW

The Kazaviti structure lies northwest of Prinos Field in the North Aegean Sea between mainland Greece and Thasos Island in a water depth of 33 m. The P-4 structure was identified with seismic data and drilled in 1976 by the Oceanic Exploration Company of Greece. The purpose of the well was to evaluate the potential of the northern portion of the Prinos Group. The primary target was the sands that are found productive in the Miocene section of Prinos Field but below the regional Lower Salt interval. The P-4 well penetrated substantially less evaporite and salt than found in Prinos Field. The well was drilled to a measured depth of 3,356 m. A stratigraphic column is shown on Figure 1.6.2.

Fifty-nine sidewall cores and an 18-m conventional core were taken in the P-4. Five DSTs were performed in several promising intervals in the well. The two deepest DSTs were unsuccessful in recovering any hydrocarbons. One of the shallow DSTs had no recovery because of tool plugging, but a second attempt over the same interval flowed oil at rates averaging 174 BOPD. The other shallow interval tested flowed oil at rates averaging 844 BOPD. The interval consisted of fair- to good-quality thin sands based on the open-hole logs. Unlike Prinos Field, no H_2S was found in the recovered oil. The interval tested could be a trap consisting of a combination of structural and stratigraphic elements. The reservoirs are interpreted as being deposited on the distal edge of a turbidite fan complex in the Prinos Group.

In 2016, Energean drilled the deviated PA-36 well offsetting the P-4 well to the southwest. The well was drilled to a total depth of 3,274 m. Only one interval was found to be productive below the Lower Salt, and that interval appears to correlate to a similar stratigraphic section that was found productive in the P-4 well. Several shallower sands above the Lower Salt calculate to be productive, but the primary focus of the well was the potential below the Lower Salt. No tests were performed in the well.

6.3.2 GEOLOGIC MAPPING

The intervals tested in the P-4 and the untested interval in the PA-36 are fair- to good-quality sands. The 3-D seismic data quality is fair to poor, and bounding faults are difficult to confidently map. It appears that a large listric fault separates the Kazaviti Discovery from Prinos Field and the sands that underlie the regional Lower Salt. We correlate the one sand below the Lower Salt in the PA-36, which we call the A Reservoir, to be separate from the two sands that were tested in the P-4, which we call the B and C Reservoirs. We have independently mapped three seismic horizons that appear to correlate to the top of the B and C Reservoirs in the P-4 and the A Reservoir in the PA-36. Depth structure maps for all three reservoirs are shown on Figures 6.6.1 through 6.6.3.

Because the sands have been correlated as three different sands, the continuity of these individual sands remains uncertain. In our petrophysical analysis, we have estimated a relatively low NTG ranging from 5 to 40 percent, a porosity ranging from 14 to 16 percent, and a water saturation ranging from 30 to 60 percent. The untested interval in the PA-36 has the best petrophysical properties.

Our low case interpretation includes only the hydrocarbons associated with the volumes above the LKO for each of the three separate sands. For the high case, we have assumed that the oil column thickness logged in each of the sands extends to the same fault or stratigraphic limit but that the area is completely filled with oil. As mapped, the overall area for each of the sands is relatively limited, with the productive areas ranging from 30 to 176 acres. A summary of the basis for the GRV calculations by zone is provided in Figure 6.6.4.

6.4 PETROPHYSICAL SUMMARY

The petrophysical evaluation methodology described in Section 1.5.1 of the Executive Summary was used for Kazaviti Discovery. The interpreted well logs for the P-4 and PA-36 wells are shown in Figures 6.6.5 and 6.6.6. The petrophysical summary table for Kazaviti Discovery is shown in Figure 6.6.7.

6.5 RESERVOIR ENGINEERING SUMMARY

Five DSTs were performed on the P-4 well, and the subsequently drilled PA-36 was not tested. Test data for the Kazaviti Discovery are shown on Figure 6.6.8.

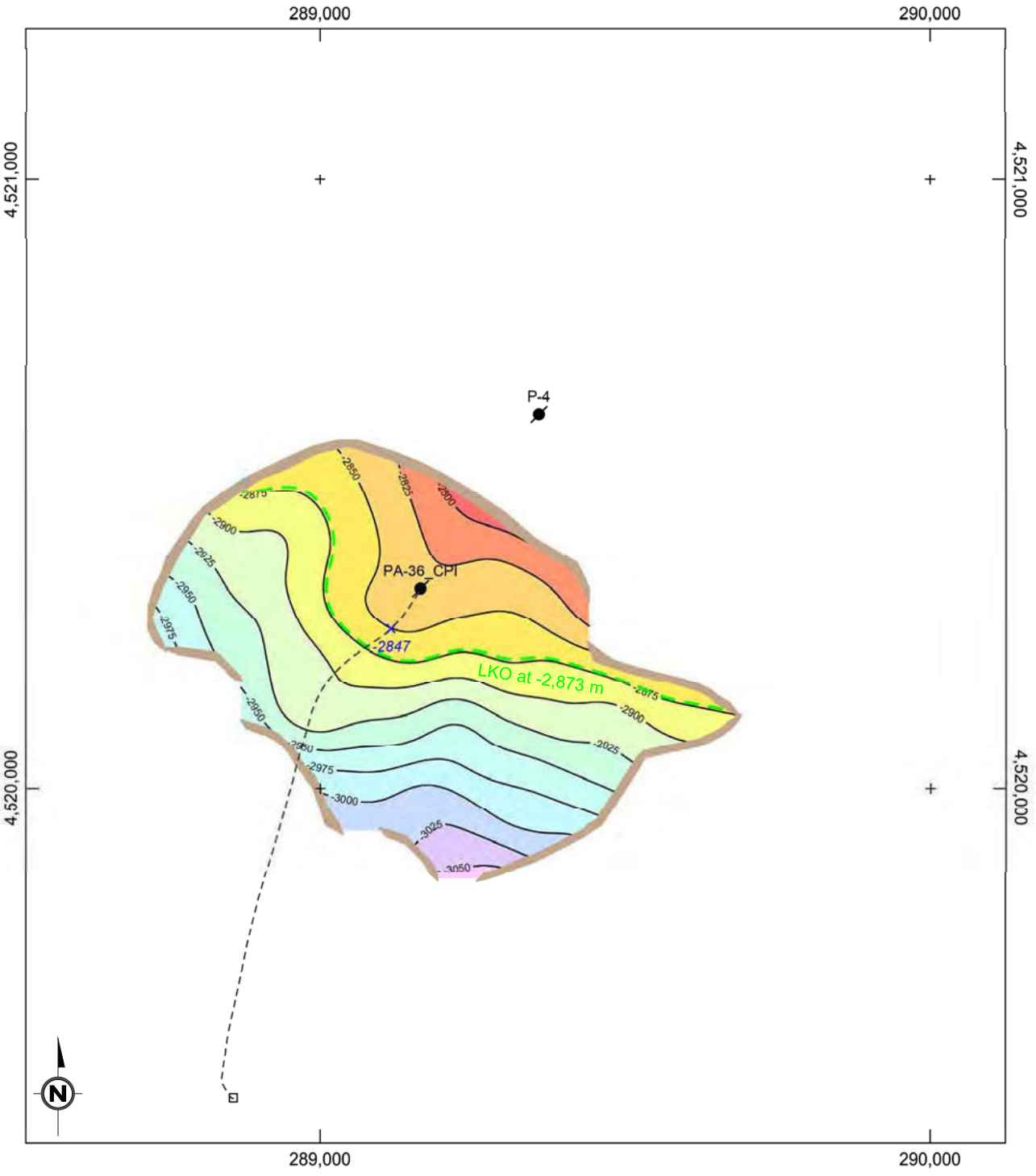
During the P-4 DSTs, separator samples were collected and recombined for PVT analysis. PVT study was limited to constant volume expansion and differential liberation experiments. Because separator tests were not carried out, we normalized the experimental solution GOR of 920 SCF/STB to the producing GOR of 420 SCF/STB observed in the P-4 well and adjusted the oil FVF accordingly. Estimated fluid and reservoir properties are summarized below by interval:

	Reservoir		
Reservoir Property	A	B	C
Datum (m TVDSS)	-2,840	-2,575	-2,640
Bottomhole Pressure (psia)	6,075	5,510	5,648
Temperature (°F)	238	215	221
Gravity (°API)	34	34	35
B_{oi} (RB/STB)	1.425	1.431	1.430
R_{si} (SCF/STB)	330	330	420

6.5.1 PROBABILISTIC RESOURCES DETERMINATION

A probabilistic spreadsheet model was constructed to calculate 1C, 2C, and 3C OOIP and gross (100 percent) technically recoverable volumes associated with contingent oil resources for Kazaviti Discovery. GRV input parameters were defined by a lognormal distribution with 98 percent confidence level and P10 input values. NTG, porosity, and hydrocarbon saturation were assigned triangular distributions based on NSAI petrophysical evaluation. Oil FVF and recovery factors were also modeled as triangular distributions with input values based on NSAI PVT work previously described and analogy to similar reservoirs.

All volumetric input parameters are summarized in Figure 6.6.9. The resulting OOIP and gross (100 percent) technically recoverable volumes associated with contingent oil resources calculated in the probabilistic model are summarized in Figure 6.6.10. Because economic analysis has not been performed on these volumes, contingent oil resources for Kazaviti Discovery are equal to the technically recoverable volumes shown on Figure 6.6.10.



Kazaviti Discovery
Offshore Greece

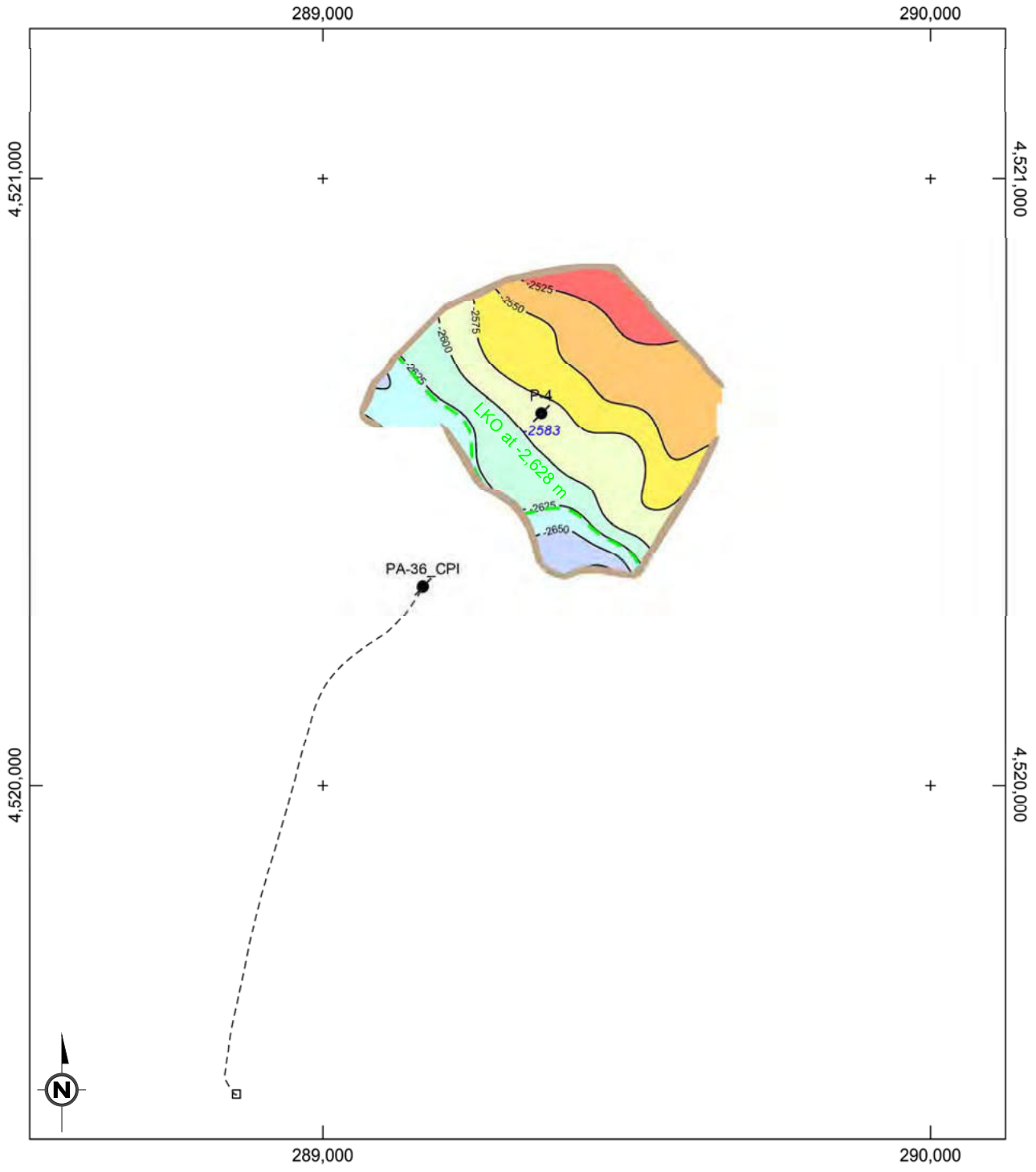
Depth Structure
Top A Reservoir

Contour Interval: 25 m

SCALE IN METERS
0 125 250 375 500

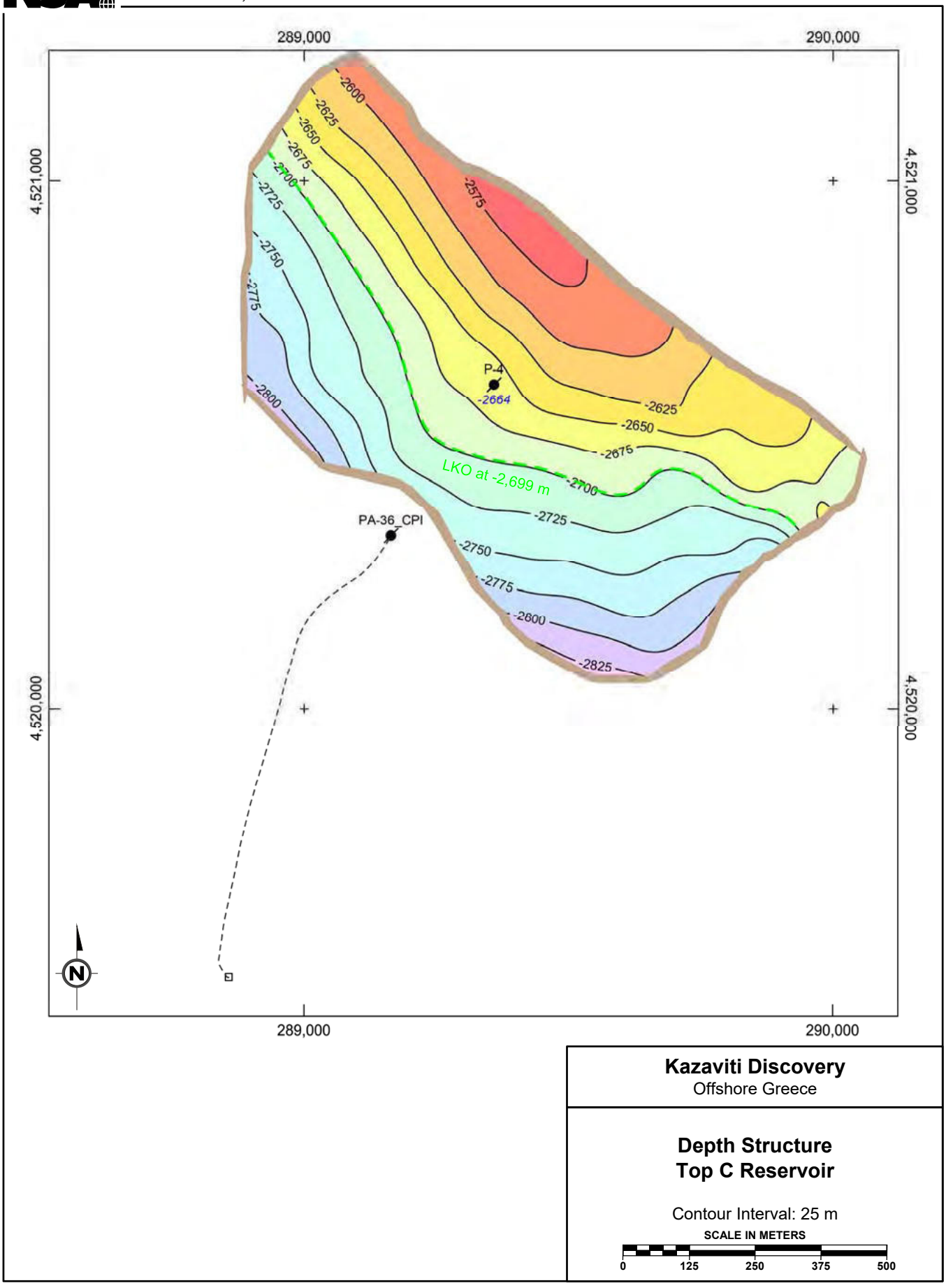
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6.6.1



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6.6.2



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6.6.3

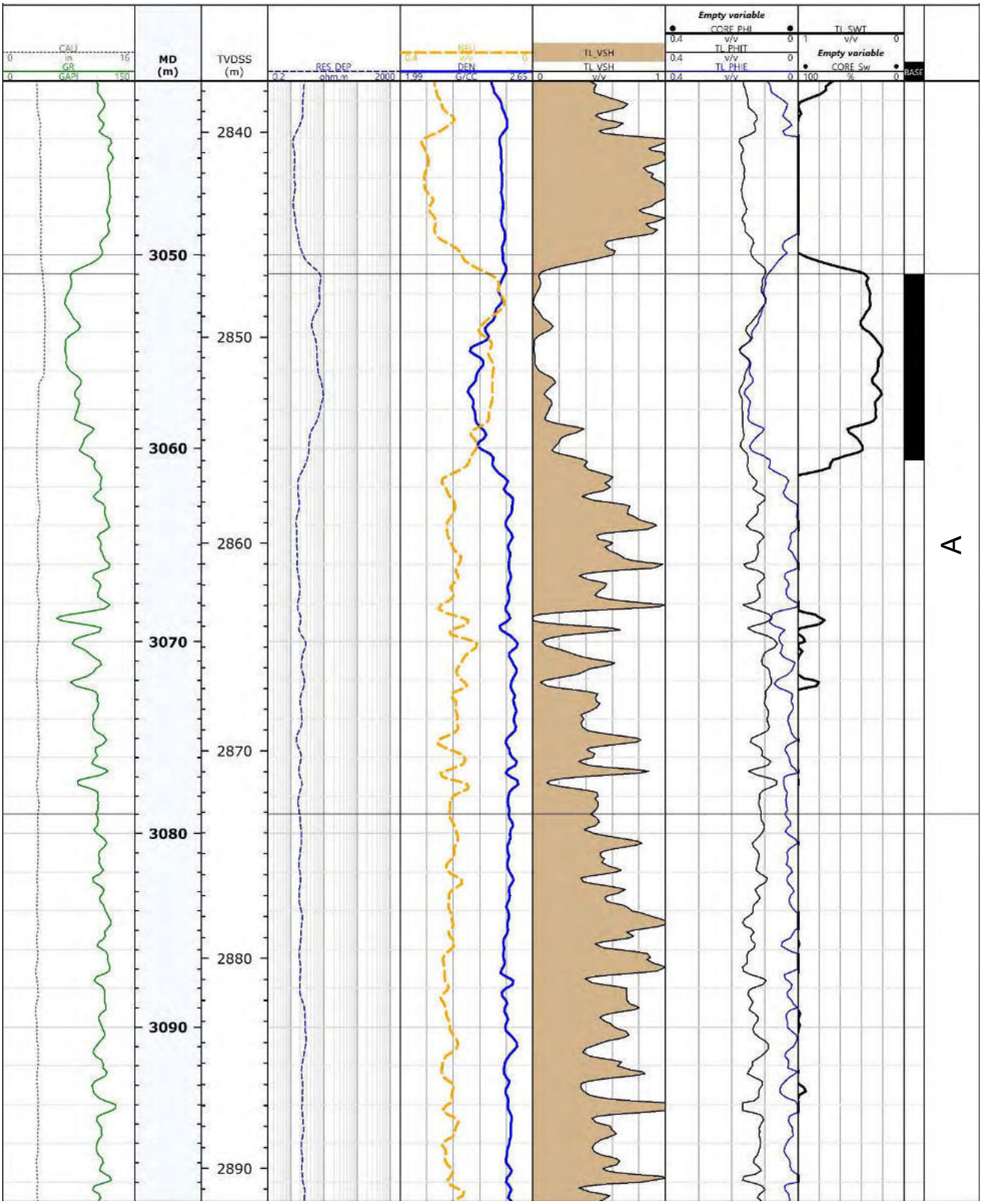
GROSS ROCK VOLUME BASIS
KAZAVITI DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	High Estimate Case	Distribution Type
A	2C	LKO (PA-36) at -2,873 m TVDSS	Fault block full	Lognormal
B	1C	LKO (P-4) at -2,628 m TVDSS	Fault block full	Lognormal
C	1C	LKO (P-4) at -2,699 m TVDSS	Fault block full	Lognormal

Figure 6.6.4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

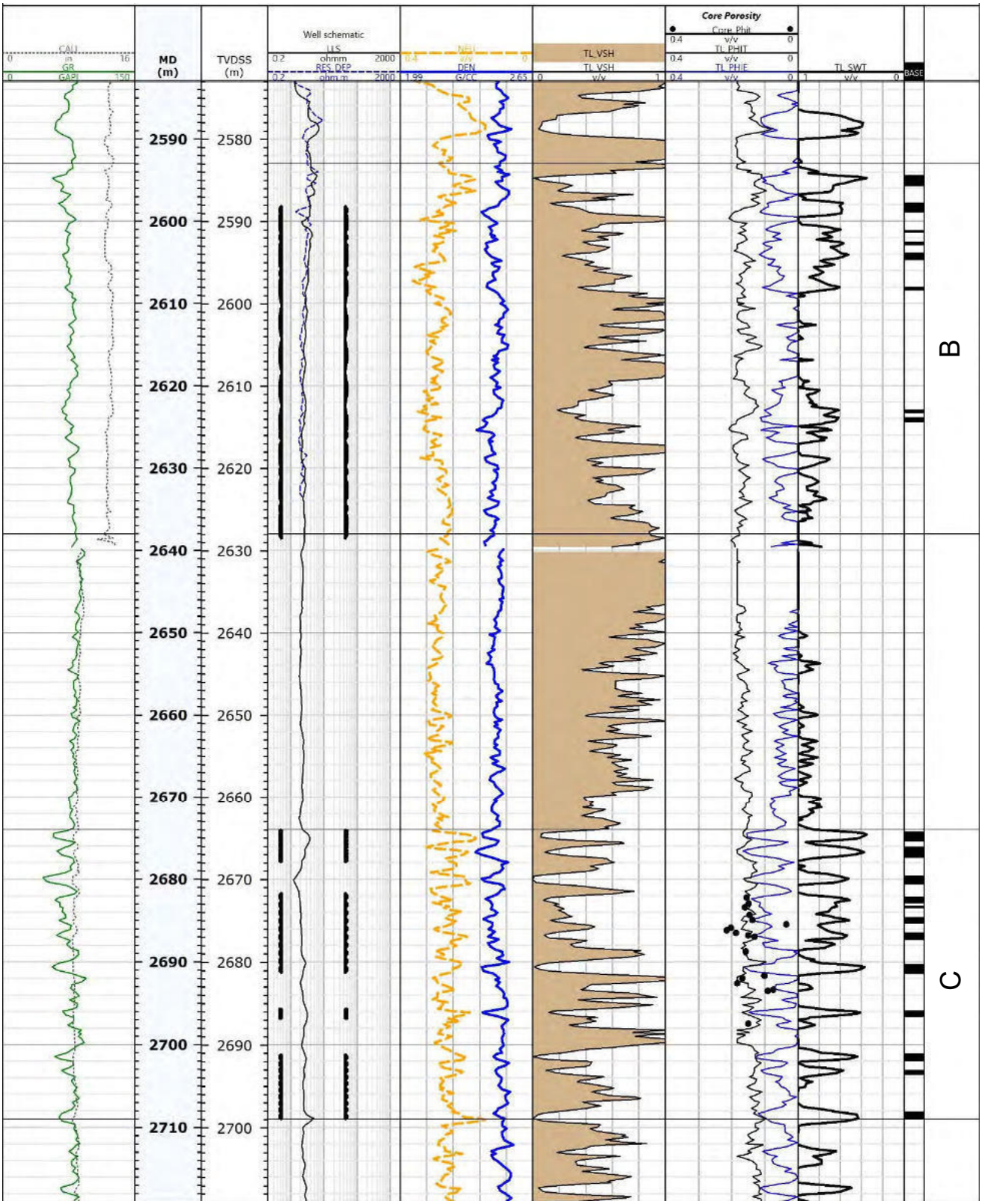
PA-36 Well
Kazaviti Discovery
Offshore Greece



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6.6.5

P-4 Well
Kazaviti Discovery
Offshore Greece



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6.6.6

PETROPHYSICAL SUMMARY
KAZAVITI DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

						Low Estimate Case			Best Estimate Case			High Estimate Case		
	Depth (m MD)		Depth (m TVDSS)		Gross Interval	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation	Net Pay	Porosity	Water Saturation
Well/Reservoir	Top	Base	Top	Base	(m)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)	(m)	(Decimal)	(Decimal)
PA-36														
A	3,051	3,079	-2,847	-2,873	26.2	8.9	0.15	0.34	9.0	0.15	0.32	9.3	0.15	0.31
P-4														
B	2,593	2,638	-2,583	-2,628	45.0	2.3	0.14	0.57	4.6	0.15	0.58	6.1	0.14	0.54
C	2,674	2,709	-2,664	-2,699	35.0	7.9	0.15	0.51	9.1	0.15	0.51	11.5	0.15	0.51
P-4 Total						10.1			13.7			17.6		

Figure 6.6.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TEST DATA
KAZAVITI DISCOVERY, OFFSHORE GREECE

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Zone	Duration (hr)	Choke (in)	Oil Rate Max (BOPD)	Oil Rate Avg (BOPD)	S_w (%)	GOR (SCF/STB)	FWHP (psig)	Gravity (°API)	CO_2 (%)	H_2S (ppm)	Comment
P-4	DST 1A	3,232	3,238												No recovery
P-4	DST 1B	3,219	3,236												No recovery
P-4	DST 2	2,674	2,709	C	3.0	64/64	1,248	1,157	Trace	470	426	35.0	3.4	Nil	
P-4	DST 2	2,674	2,709	C	8.5	32/64	1,317	844	Trace	421	269	36.3	3.4	Nil	
P-4	DST 3A	2,598	2,639	B											Tools plugged
P-4	DST 3B	2,598	2,639	B	6.0	32/64	403	174	N/A	330	117	34.0	3.0	Nil	No stabilized flow

Figure 6.6.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH CONTINGENT OIL RESOURCES
KAZAVITI DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category[1]	Gross Rock Volume (Acre-Feet) P98	P50	P10	Net-to-Gross Ratio (Decimal) Min	Most Likely	Max	Porosity (Decimal) Min	Most Likely	Max
A	2C	2,014	N/A	8,340	0.30	0.35	0.40	0.14	0.15	0.16
B	1C	4,840	N/A	6,778	0.05	0.10	0.15	0.14	0.15	0.16
C	1C	9,448	N/A	20,214	0.23	0.26	0.33	0.14	0.15	0.16

Reservoir	Category[1]	Hydrocarbon Saturation (Decimal) Min	Most Likely	Max	Formation Volume Factor (RB/STB) Min	Most Likely	Max	Recovery Factor (Decimal) Min	Most Likely	Max
A	2C	0.65	0.68	0.70	1.42	1.43	1.44	0.20	0.30	0.40
B	1C	0.40	0.42	0.45	1.42	1.43	1.44	0.20	0.30	0.40
C	1C	0.45	0.49	0.55	1.42	1.43	1.44	0.20	0.30	0.40

[1] For reservoirs categorized as 1C, we have estimated 1C, 2C, and 3C technically recoverable volumes associated with contingent resources. For zones categorized as 2C, we have estimated 2C and 3C technically recoverable volumes associated with contingent resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH CONTINGENT OIL RESOURCES
KAZAVITI DISCOVERY, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
Reservoir	1C	2C	3C	1C	2C	3C	1C	2C	3C
A	0.0	0.9	1.6	0.0	0.3	0.5	0	30	31
B	0.1	0.2	0.3	0.0	0.1	0.1	26	30	34
C	1.2	1.7	2.3	0.3	0.5	0.8	27	30	33
Arithmetic Sum[3]	1.3	2.8	4.2	0.4	0.8	1.4	27	30	32
Probabilistic Sum	1.4	2.9	3.8	0.4	0.9	1.2	27	30	33

(1) Because economic analysis has not been performed on these volumes, contingent oil resources for Kazaviti Field are equal to the technically recoverable volumes shown.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

(3) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ALPHA LEAD

TECHNICAL DISCUSSION
ALPHA LEAD
OFFSHORE GREECE

7.1 OVERVIEW

Alpha Lead is located east of Prinos North Field and is fault separated. A location map is shown on Figure 1.6.1. The primary target of the lead is the interval below the evaporite and salt sequence, which is found within the Prinos Equivalent zone. A geologic risk assessment was performed for this lead, as discussed in subsequent paragraphs. A stratigraphic column is shown on Figure 1.6.2.

We estimate the gross (100 percent) unrisked and risked prospective resources for Alpha Lead, as of October 31, 2017, to be:

Gross (100%) Prospective Oil Resources (MMBBL)					
Unrisked			Risked		
Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
4.6	6.3	8.6	0.7	1.0	1.4

7.2 DATA SOURCES

Data were provided to us by Energean. The key data utilized in our evaluation are listed in the Executive Summary.

7.3 GEOPHYSICAL AND GEOLOGICAL SUMMARY

Alpha Lead is primarily a fault-bounded structure with three-way dip closure. The lead is in an upthrown fault block that separates it from the Prinos North reservoir. The general structural axis is oriented in a northeast-to-southwest direction. Because of its close proximity to Prinos North Field, the target reservoir should have similar petrophysical characteristics. A structure map for Alpha Reservoir is included in Figure 7.5.1.

We have assumed that the fault block is 50 percent filled in the low case and full in the high case, with a gross reservoir thickness of 25 m. We used a lognormal distribution in estimating the GRV for Alpha Lead. A summary of the basis for the GRV calculations zone is provided in Figure 7.5.2. We have estimated a NTG ranging from 50 to 80 percent, porosity ranging from 15 to 20 percent, and water saturation ranging from 30 to 50 percent.

Because of the inherent risk associated with prospective resources, a geologic risk factor was applied to the gross (100 percent) volumes. A geologic risk factor considers each of the elements of a successful petroleum system, which include the presence of organically rich, thermally mature source beds capable of generating hydrocarbons as well as the presence of adequate migration pathways for mature hydrocarbons to migrate out of source beds into porous and permeable reservoir beds.

We conducted a geologic risk assessment for Alpha Lead using a four-component methodology based on Otis and Schneidermann[1] to measure the P_g. Geologic risk assessment addresses the probability of success for discovering hydrocarbons without regard to commerciality. Each of the four elements is assigned a value from 0.0 to 1.0, and the product of the four components is the overall P_g. Principal geologic elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Because of the subjective nature of geologic risk assessment, any such assessment is highly dependent on the experience of the evaluators, the data available to define each prospect, the regional data describing reservoir and production characteristics, and the historical local and regional hydrocarbon discovery success rates. Otis and Schneidermann define a P_g greater than 0.50 as very low risk, a P_g between 0.50 and 0.25 as low risk, a P_g between 0.25 and 0.125 as moderate risk, a P_g between 0.125 and 0.063 as high risk, and a P_g below 0.063 as very high risk exploration opportunities. Our final P_g estimate for this lead is 0.16 , with the biggest risk component being lack of reservoir quality.

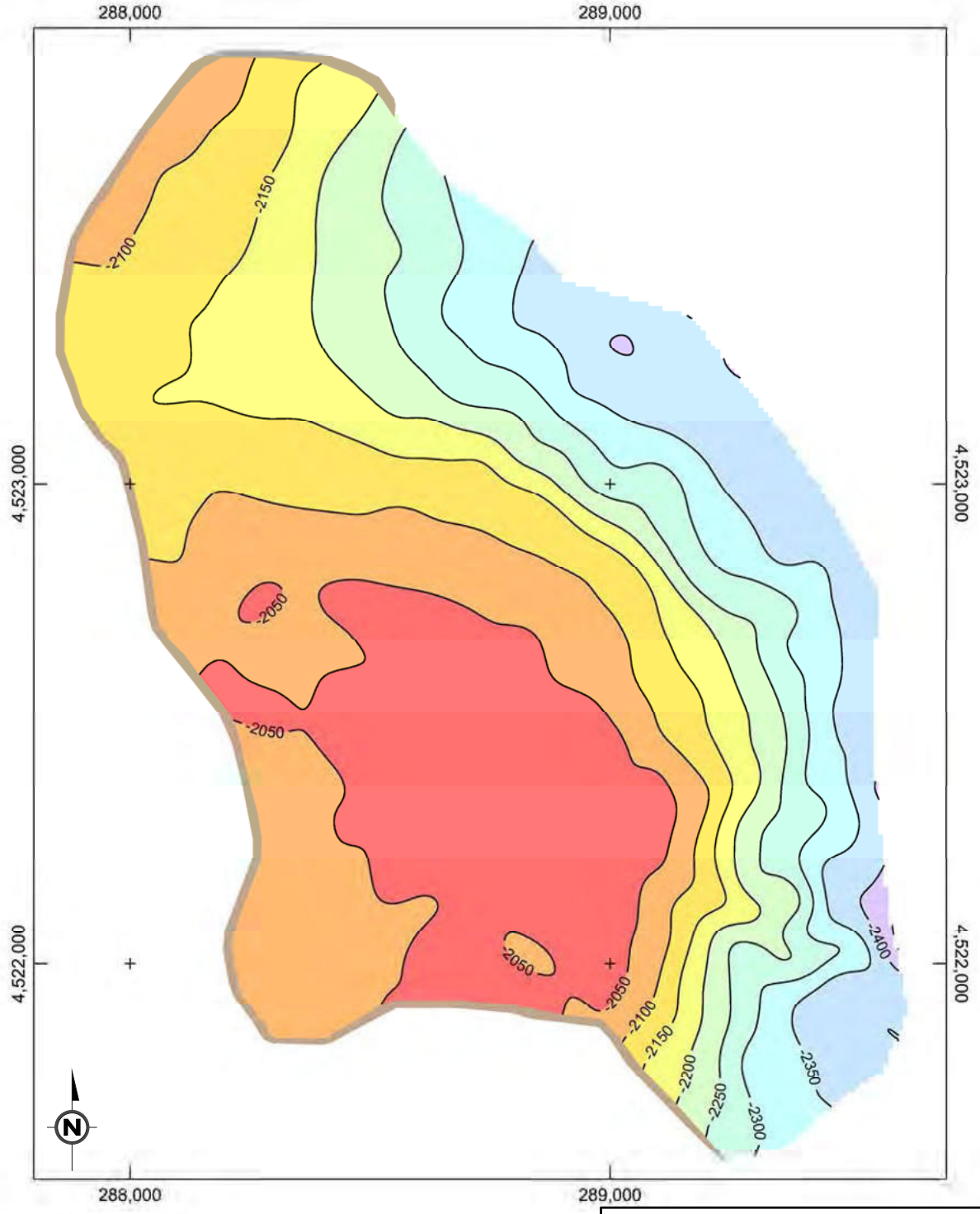
Alpha is currently considered a lead because sufficient technical work has not yet been done by Energean to consider this a drill-ready prospect. Energean's structural interpretation and expected reservoir parameters for Alpha Lead are still in an early technical phase. Even though Alpha is a lead, we did a full technical analysis in our evaluation, including an independent structural interpretation and estimation of GRV, petrophysical parameters, and recovery factors.

7.4 RESERVOIR ENGINEERING METHODOLOGY

A probabilistic spreadsheet model was constructed to calculate low, best, and high estimate OOIP and prospective oil resources for Alpha Lead. We determined the type of distribution and input parameters for the various volumetric parameters. GRV input parameters were defined by a lognormal distribution with P90 and P10 input parameters as previously discussed. The remaining volumetric parameters of NTG, porosity, hydrocarbon saturation, formation volume factor, and recovery factor were all input as triangular distributions. Probability ranges for all volumetric parameters were estimated based on analogous fields in the region and our knowledge of similar reservoirs.

All volumetric input parameters are summarized on Figure 7.5.3. The resulting unrisked and risked OOIP and gross (100 percent) prospective resources calculated in the probabilistic model are summarized on Figures 7.5.4 and 7.5.5.

[1] Otis, R.M. and N. Schneidermann, 1997, A Process for Evaluating Exploration Prospects, *AAPG Bulletin*, Volume 81, Number 7, pages 1087-1109.



Alpha Lead
Offshore Greece

Depth Structure
Top Alpha Reservoir

Contour Interval: 50 m

SCALE IN METERS
0 125 250 375 500

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7.5.1

GROSS ROCK VOLUME BASIS
ALPHA LEAD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	High Estimate Case	Distribution Type
Alpha	Low	Half of the structure filled	Fault block full	Lognormal

Figure 7.5.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH PROSPECTIVE OIL RESOURCES
ALPHA LEAD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
						Most			Most	
Reservoir	Category[1]	P90	P50	P10	Min	Likely	Max	Min	Likely	Max
Alpha	Low	35,544	N/A	52,820	0.50	0.76	0.80	0.15	0.18	0.20

		Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
			Most			Most			Most	
Reservoir	Category[1]	Min	Likely	Max	Min	Likely	Max	Min	Likely	Max
Alpha	Low	0.50	0.68	0.70	1.15	1.20	1.25	0.20	0.30	0.40

[1] For reservoirs categorized as low, we have estimated low, best, and high technically recoverable volumes associated with prospective resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF UNDISCOVERED ORIGINAL OIL-IN-PLACE AND
UNRISKED GROSS (100 PERCENT) PROSPECTIVE OIL RESOURCES
ALPHA LEAD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Undiscovered Original Oil-in-Place (MMBBL)			Unrisked Gross (100%) Prospective Oil Resources (MMBBL)			Recovery Factor[(1)] (%)		
Reservoir	Low	Best	High	Low	Best	High	Low	Best	High
Alpha	16.1	21.2	27.5	4.6	6.3	8.6	28	30	31

(1) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Prospective Oil Resources by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF GROSS (100 PERCENT) UNRISKED AND RISKED PROSPECTIVE OIL RESOURCES
ALPHA LEAD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

		Unrisked Oil (MMBBL)						Risked Oil (MMBBL)					
		Undiscovered Original In-Place			Gross Recoverable			Undiscovered Original In-Place			Gross Recoverable		
Reservoir	P_g (Decimal)	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Alpha	0.16	16.1	21.2	27.5	4.6	6.3	8.6	2.6	3.4	4.4	0.7	1.0	1.4

Figure 7.5.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

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November 22, 2017

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Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked gross (100 percent) prospective resources, as of October 31, 2017, for certain prospects and leads located offshore Montenegro and onshore Greece. We completed our evaluation on or about the date of this letter. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE); definitions are presented immediately following this letter. Following the definitions are certificates of qualification. This report has been prepared for use by Energean Oil & Gas PLC (Energean) in filing with the London Stock Exchange; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. The undiscovered accumulations assessed in this report have been subclassified as prospects and leads. The 2007 PRMS defines a prospect as a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target, a lead as a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be subclassified as a prospect, and a play as a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A geologic risk assessment was performed for these prospects and leads, as discussed in subsequent paragraphs. We did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

Totals of unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect and lead, meaningful totals beyond these levels can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources, the on-lease area percentage, and the probability of geologic success (P_g) for these prospects, as of October 31, 2017, to be:

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Country/Prospect	Unrisked Gross (100%) Prospective Resources[1] Liquids (MMBBL) Low Estimate	Best Estimate	High Estimate	Gas (BCF) Low Estimate	Best Estimate	High Estimate	On-Lease Area[2] (%) Low Estimate	High Estimate	P_g (%)
Montenegro									
Diapir Pliocene	0.0	0.0	0.0	69.9	200.1	433.7	81	79	25
Diapir Pre-Messinian	0.5	3.8	29.1	181.2	454.9	895.2	93	61	17
Pliocene 1	0.0	0.0	0.0	19.2	30.3	45.9	100	100	45
Pliocene 2	0.0	0.0	0.0	49.6	78.3	118.1	100	100	45
Pliocene 3 North	0.0	0.0	0.0	23.7	38.7	61.3	100	100	45
Pliocene 3 South	0.0	0.0	0.0	14.3	24.1	39.3	100	100	28
Pliocene Channel A	0.0	0.0	0.0	12.6	28.7	58.6	100	100	22

(1) Unrisked gross (100 percent) prospective resources include on-lease and off-lease volumes.
(2) The on-lease area percentage is based on the low estimate and high estimate mapped areas. These areas were used as inputs in our probabilistic model.

The liquids volumes shown include condensate and natural gas liquids. Liquids volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

We estimate the unrisked gross (100 percent) prospective resources, the on-lease area percentage, and the P_g for these leads, as of October 31, 2017, to be:

Country/Lead	Unrisked Gross (100%) Prospective Resources[1] Liquids (MMBBL) Low Estimate	Best Estimate	High Estimate	Gas (BCF) Low Estimate	Best Estimate	High Estimate	On-Lease Area[2] (%) Low Estimate	High Estimate	P_g (%)
Montenegro									
Deep Clastic North	0.4	4.0	30.5	218.3	484.3	861.7	85	85	12
Deep Clastic South	0.3	2.8	22.0	160.3	352.7	643.3	55	55	12
Sub-Thrust[3]	40.3	133.3	390.7	21.2	74.4	234.5	92	87	13
Greece									
Raeko[3]	57.8	187.1	410.0	31.0	103.3	249.0	100	100	15

(1) Unrisked gross (100 percent) prospective resources include on-lease and off-lease volumes.
(2) The on-lease area percentage is based on the low estimate and high estimate mapped areas. These areas were used as inputs in our probabilistic model.
(3) The Sub-Thrust and Raeko Leads are expected to be naturally-fractured carbonate reservoirs. Volumes for these leads are the arithmetic sum of probability distributions of their respective fracture volume and matrix volume.

The liquids volumes shown include crude oil, condensate, and natural gas liquids.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that

the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The low, best, and high estimate prospective resources for the Sub-Thrust and Raeko Leads have been aggregated beyond the fracture volume and matrix volume levels by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation.

Each prospect and lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects and leads may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects and leads.

For the purposes of this report, we did not perform any field inspection of the prospects and leads. We have not investigated possible environmental liability related to the prospects and leads.

For the purposes of this report, we used technical data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests. The resources in this report have been estimated using probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energean, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the prospects and leads or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates

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presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these prospects and leads nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ John R. Cliver
By:
John R. Cliver, P.E. 107216
Vice President

Date Signed: November 22, 2017

/s/ Zachary R. Long
By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: November 22, 2017

JRC:DMN

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

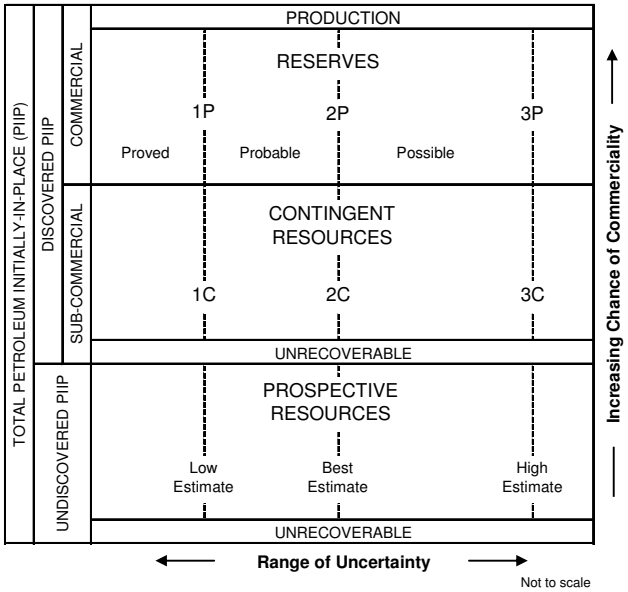


Figure 1-1: Resources Classification Framework.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

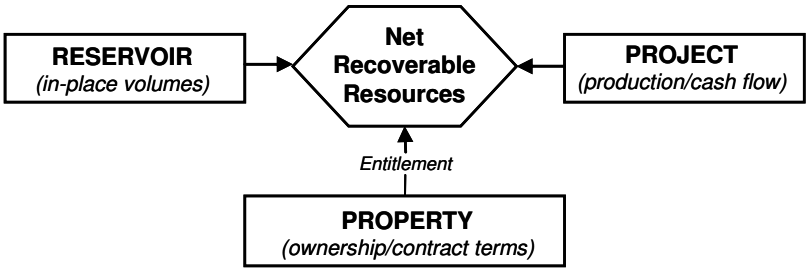


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Class/Sub-Class	**Definition**	**Guidelines**
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	**Definition**	**Guidelines**
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, John R. Cliver, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a prospective resources evaluation for Energean Oil & Gas PLC. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas PLC or its affiliated companies.

I attended University of Texas at Austin, and I graduated in 2008 with a Master of Business Administration Degree. I attended Rice University, and I graduated in 2004 with a Bachelor of Science Degree in Chemical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 13 years of experience in petroleum engineering studies and evaluations.

/s/ John R. Cliver

By: _____

John R. Cliver, P.E.
Vice President
Texas License No. 107216

November 22, 2017
Houston, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Zachary R. Long, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a prospective resources evaluation for Energean Oil & Gas PLC. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas PLC or its affiliated companies.

I attended Texas A&M University, and I graduated in 2005 with a Master of Science Degree. I attended University of Louisiana at Lafayette, and I graduated in 2003 with a Bachelor of Science Degree in Geology; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 12 years of experience in petroleum engineering studies and evaluations.

/s/ Zachary R. Long

By: _____

Zachary R. Long, P.G.
Vice President
Texas License No. 11792

November 22, 2017
Houston, Texas

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ESTIMATES

of

GROSS (100 PERCENT) OIL RESERVES AND FUTURE REVENUE AND CONTINGENT GAS RESOURCES

for

CERTAIN OIL AND GAS PROPERTIES

located in

WEST KATAKOLO FIELD, OFFSHORE GREECE

as of

OCTOBER 31, 2017

Prepared for and

BASED ON PRICE AND COST PARAMETERS

specified by

ENERGEAN OIL & GAS SA

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

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January 23, 2018

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London W1U 8HR
United Kingdom

Energean Oil & Gas SA
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Ladies and Gentlemen:

In accordance with your request, we have estimated the gross (100 percent) proved undeveloped, probable, and possible oil reserves and future revenue, as of October 31, 2017, for certain oil and gas properties located in West Katakolo Field, offshore Greece. Also as requested, we have estimated the gross (100 percent) contingent gas resources, as of October 31, 2017, for certain oil and gas properties located in West Katakolo Field, offshore Greece. Energean Oil & Gas SA (Energean) owns 100 percent interest in these properties. We completed our evaluation on or about January 12, 2018. This report has been prepared using price and cost parameters specified by Energean, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification and a list of abbreviations used in this report. This report has been prepared for use by Energean Oil & Gas PLC in filing with the London Stock Exchange: in our opinion the assumptions, data, methods, and procedures used in preparation of this report are appropriate for such purpose.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) oil reserves and future net revenue for West Katakolo Field, as of October 31, 2017, to be:

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Category	Gross (100%) Oil Reserves (MMBBL)	Future Net Revenue After Income Tax[1] (MM$) Total	Future Net Revenue After Income Tax[1] (MM$) Present Worth at 10%
Proved Undeveloped	6.3	126.8	59.0
Proved (1P)	6.3	126.8	59.0
Probable	4.2	146.1	55.1
Proved + Probable (2P)	10.5	272.9	114.1
Possible	5.8	214.0	52.5
Proved + Probable + Possible (3P)	16.3	486.9	166.6

[1] Taxes include both corporate and municipality taxes.

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of October 31, 2017, there are no proved developed reserves for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves shown in this report is the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for capital costs, abandonment costs, operating expenses, royalties owed to the Greek government, and corporate and municipality income taxes. It is our understanding that Energean has a $77,000 tax loss carryforward, which is accounted for in our estimates of future net revenue. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using oil price parameters specified by Energean. Oil prices are based on October 31, 2017, Dated Brent prices and are adjusted for quality, transportation fees, and market differentials. All prices are escalated 2 percent on January 1 of each year throughout the lives of the properties. Oil prices before adjustments, both before and after escalation, are shown in the following table:

Period Ending	Base Oil Price ($/Barrel)	Escalated Oil Price ($/Barrel)
12-31-2017	60.00	60.00
12-31-2018	62.50	63.75
12-31-2019	65.00	67.63
Thereafter	65.00	Escalated 2 percent on January 1 of each year.

Operating costs used in this report are based on operating expense records and budgets of Energean, the operator of the properties, and include only direct lease-level and field-level costs. As requested, headquarters general and administrative overhead expenses of Energean are not included. Also as requested, operating costs are escalated 2 percent on January 1 of each year throughout the lives of the properties.

Capital costs used in this report were provided by Energean and are based on budgeted expenditures and authorizations for expenditure. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Energean's estimates of the costs to abandon the wells and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report are subclassified as development unclarified and are contingent upon further appraisal and development of a plan to commercialize the gas resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. We did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the unrisked gross (100 percent) contingent gas resources for West Katakolo Field, as of October 31, 2017, to be:

Category	Unrisked Gross (100%) Contingent Gas Resources (BCF)
Low Estimate (1C)	3.7
Best Estimate (2C)	6.2
High Estimate (3C)	9.6

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The contingent resources shown in this report have been estimated using probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes summary projections of reserves and revenue by reserves category and a technical discussion with pertinent maps and figures.

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes

in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Energean, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energean and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Philip S. (Scott) Frost
By:
Philip S. (Scott) Frost, P.E. 88738
Senior Vice President

Date Signed: January 23, 2018

/s/ Michelle F. Herrera
By:
Michelle F. Herrera, P.G. 11912
Geoscientist

Date Signed: January 23, 2018

PSF:TDL

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NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

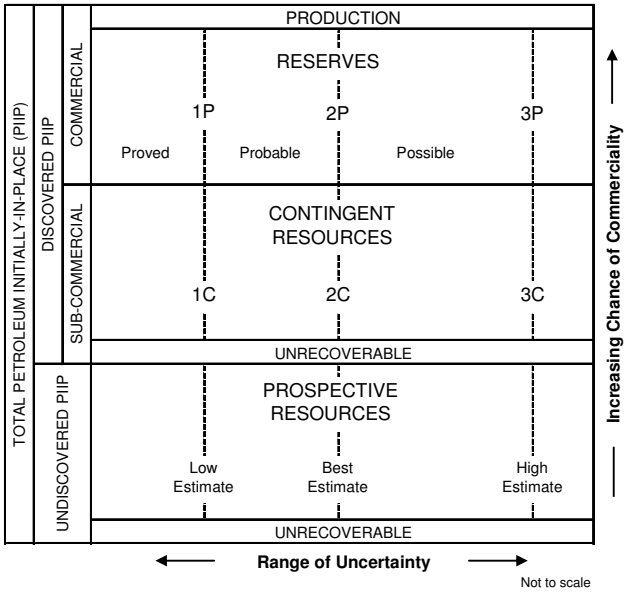


Figure 1-1: Resources Classification Framework.

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

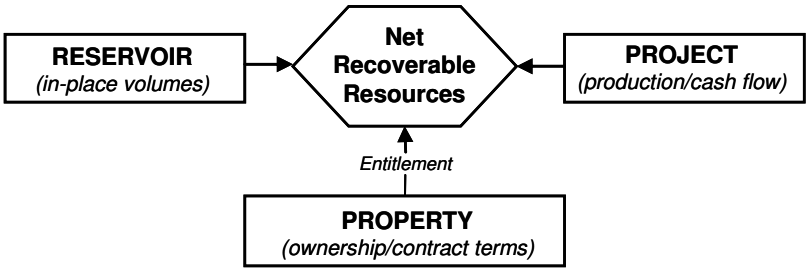


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	**Definition**	**Guidelines**
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	**Definition**	**Guidelines**
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Philip S. (Scott) Frost, Licensed Professional Engineer, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Energean Oil & Gas SA. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas SA or its affiliated companies.

I attended Tulane University, and I graduated in 1984 with a Master's Degree in Business Administration; I attended Vanderbilt University, and I graduated in 1979 with a Bachelor of Engineering Degree in Mechanical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 36 years of experience in petroleum engineering studies and evaluations.

/s/ Philip S. (Scott) Frost

By: _____

Philip S. (Scott) Frost, P.E.
Senior Vice President
Texas Registration No. 88738

January 23, 2018
Dallas, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Michelle F. Herrera, Licensed Professional Geoscientist, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Energean Oil & Gas SA. The effective date of this evaluation is October 31, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Energean Oil & Gas SA or its affiliated companies.

I attended University of Texas at Dallas, I graduated in 2002 with a Bachelor of Science Degree in Geoscience; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 15 years of experience in geological and geophysical studies and evaluations.

/s/ Michelle F. Herrera
By: _____
Michelle F. Herrera, P.G.
Geoscientist
Texas Registration No. 11912

January 23, 2018
Dallas, Texas

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NETHERLAND, SEWELL & ASSOCIATES, INC.

ABBREVIATIONS

$	United States dollars
°	degrees
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
1P	proved
2C	best estimate scenario of contingent resources
2P	proved plus probable
3C	high estimate scenario of contingent resources
3P	proved plus probable plus possible
API	American Petroleum Institute
BBL/D	barrels per day
BBL/MMCF	barrels per million cubic feet
BCF	billions of cubic feet
BOPD	barrels of oil per day
CPI	computer-processed interpretation
DEP	Public Petroleum Corporation S.A.
DST	drillstem test
Energean	Energean Oil & Gas SA
FVF	formation volume factor
GOC	gas-oil contact
GRV	gross rock volume
H_2S	hydrogen sulfide
hr	hour
m	meters
MD	measured depth
MM$	millions of United States dollars
MMBBL	millions of barrels
MMCFD	millions of cubic feet per day
MWh	megawatt hour
NSAI	Netherland, Sewell & Associates, Inc.
NTG	net-to-gross ratio
OWC	oil-water contact
P50	50 percent confidence level
P90	90 percent confidence level
ppm	parts per million
PRMS	Petroleum Resources Management System
PSC	production sharing contract
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
RB/STB	reservoir barrel per stock tank barrel
SCF/ft^3	standard cubic feet per reservoir cubic foot
SCF/STB	standard cubic feet per stock tank barrel
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
TVDSS	true vertical depth subsea

NETHERLAND, SEWELL & ASSOCIATES, INC.

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NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

PROVED UNDEVELOPED RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	65.9	0.0	0.0	0.0	0.0	(65.9)	(56.2)
12-31-2020	1,313	0.5	0.0	29.5	5.0	0.0	6.0	0.6	2.7	15.1	(44.5)
12-31-2021	2,185	0.8	0.0	50.1	13.0	0.0	8.3	3.1	4.7	21.1	(29.7)
12-31-2022	3,327	1.2	0.0	78.0	13.2	0.0	10.2	6.2	7.6	40.7	(3.6)
12-31-2023	2,733	1.0	0.0	65.5	0.0	0.0	9.7	8.4	5.3	42.1	21.0
12-31-2024	2,285	0.8	0.0	56.0	0.0	0.0	9.3	6.2	8.1	32.4	38.1
12-31-2025	1,839	0.7	0.0	46.1	0.0	0.0	8.9	5.1	8.0	24.0	49.7
12-31-2026	1,504	0.5	0.0	38.5	0.0	0.0	8.7	6.5	5.8	17.5	57.3
12-31-2027	1,033	0.4	0.0	27.0	0.0	0.0	7.5	3.0	4.1	12.4	62.3
12-31-2028	632	0.2	0.0	16.9	0.0	0.0	7.1	1.9	2.0	6.0	64.4
12-31-2029	396	0.1	0.0	10.8	0.0	0.0	6.9	1.2	0.7	2.1	65.1
12-31-2030	0	0.0	0.0	0.0	0.0	20.6	0.0	0.0	0.0	(20.6)	59.0
12-31-2031											
12-31-2032											
12-31-2033											
12-31-2034											
12-31-2035											
12-31-2036											
SUBTOTAL		6.3	0.0	418.4	97.2	20.6	82.6	42.0	49.1	126.8	59.0
REMAINING		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.0
TOTAL 14 YRS		6.3	0.0	418.4	97.2	20.6	82.6	42.0	49.1	126.8	59.0
CUM PROD		0.0	0.0								
ULTIMATE		6.3	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	69.1
FOR 15 PCT, PRESENT WORTH MM$	38.7
FOR 20 PCT, PRESENT WORTH MM$	24.1
FOR 25 PCT, PRESENT WORTH MM$	13.5
FOR 30 PCT, PRESENT WORTH MM$	5.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

PROVED (1P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	65.9	0.0	0.0	0.0	0.0	(65.9)	(56.2)
12-31-2020	1,313	0.5	0.0	29.5	5.0	0.0	6.0	0.6	2.7	15.1	(44.5)
12-31-2021	2,185	0.8	0.0	50.1	13.0	0.0	8.3	3.1	4.7	21.1	(29.7)
12-31-2022	3,327	1.2	0.0	78.0	13.2	0.0	10.2	6.2	7.6	40.7	(3.6)
12-31-2023	2,733	1.0	0.0	65.5	0.0	0.0	9.7	8.4	5.3	42.1	21.0
12-31-2024	2,285	0.8	0.0	56.0	0.0	0.0	9.3	6.2	8.1	32.4	38.1
12-31-2025	1,839	0.7	0.0	46.1	0.0	0.0	8.9	5.1	8.0	24.0	49.7
12-31-2026	1,504	0.5	0.0	38.5	0.0	0.0	8.7	6.5	5.8	17.5	57.3
12-31-2027	1,033	0.4	0.0	27.0	0.0	0.0	7.5	3.0	4.1	12.4	62.3
12-31-2028	632	0.2	0.0	16.9	0.0	0.0	7.1	1.9	2.0	6.0	64.4
12-31-2029	396	0.1	0.0	10.8	0.0	0.0	6.9	1.2	0.7	2.1	65.1
12-31-2030	0	0.0	0.0	0.0	0.0	20.6	0.0	0.0	0.0	(20.6)	59.0
12-31-2031											
12-31-2032											
12-31-2033											
12-31-2034											
12-31-2035											
12-31-2036											
SUBTOTAL		6.3	0.0	418.4	97.2	20.6	82.6	42.0	49.1	126.8	59.0
REMAINING		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.0
TOTAL 14 YRS		6.3	0.0	418.4	97.2	20.6	82.6	42.0	49.1	126.8	59.0
CUM PROD		0.0	0.0								
ULTIMATE		6.3	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	69.1
FOR 15 PCT, PRESENT WORTH MM$	38.7
FOR 20 PCT, PRESENT WORTH MM$	24.1
FOR 25 PCT, PRESENT WORTH MM$	13.5
FOR 30 PCT, PRESENT WORTH MM$	5.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

PROBABLE RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2021	2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2022	270	0.1	0.0	6.3	0.0	0.0	0.3	1.7	0.5	3.9	2.5
12-31-2023	360	0.1	0.0	8.6	0.0	0.0	0.4	(0.2)	1.2	7.1	6.7
12-31-2024	529	0.2	0.0	13.0	0.0	0.0	0.7	1.4	4.2	6.7	10.2
12-31-2025	661	0.2	0.0	16.6	0.0	0.0	0.8	6.0	2.4	7.3	13.7
12-31-2026	659	0.2	0.0	16.9	0.0	0.0	0.9	1.2	3.7	11.1	18.6
12-31-2027	870	0.3	0.0	22.8	0.0	0.0	1.9	4.0	4.2	12.6	23.6
12-31-2028	1,069	0.4	0.0	28.6	0.0	0.0	2.2	4.5	5.5	16.4	29.5
12-31-2029	1,149	0.4	0.0	31.4	0.0	0.0	2.4	4.7	6.1	18.2	35.5
12-31-2030	1,424	0.5	0.0	39.8	0.0	(20.6)	8.5	5.6	6.4	39.9	47.4
12-31-2031	1,268	0.5	0.0	36.2	0.0	0.0	8.4	5.1	5.7	17.0	52.1
12-31-2032	985	0.4	0.0	28.7	0.0	0.0	8.2	4.0	4.1	12.4	55.1
12-31-2033	789	0.3	0.0	23.5	0.0	0.0	8.0	3.3	3.0	9.1	57.2
12-31-2034	632	0.2	0.0	19.2	0.0	0.0	8.0	5.6	1.4	4.3	58.1
12-31-2035	425	0.2	0.0	13.2	0.0	0.0	7.8	1.9	0.9	2.7	58.6
12-31-2036	333	0.1	0.0	10.6	0.0	0.0	7.8	1.5	0.3	1.0	58.7
SUBTOTAL		4.2	0.0	315.4	0.0	(20.6)	66.4	50.2	49.7	169.7	58.7
REMAINING		0.0	0.0	0.0	0.0	23.7	0.0	0.0	0.0	(23.7)	55.1
TOTAL 21 YRS		4.2	0.0	315.4	0.0	3.1	66.4	50.2	49.7	146.1	55.1
CUM PROD		0.0	0.0								
ULTIMATE		4.2	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	66.4
FOR 15 PCT, PRESENT WORTH MM$	35.4
FOR 20 PCT, PRESENT WORTH MM$	23.4
FOR 25 PCT, PRESENT WORTH MM$	15.9
FOR 30 PCT, PRESENT WORTH MM$	11.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

PROVED + PROBABLE (2P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	65.9	0.0	0.0	0.0	0.0	(65.9)	(56.2)
12-31-2020	1,313	0.5	0.0	29.5	5.0	0.0	6.0	0.6	2.7	15.1	(44.5)
12-31-2021	2,188	0.8	0.0	50.2	13.0	0.0	8.3	3.1	4.7	21.1	(29.6)
12-31-2022	3,596	1.3	0.0	84.3	13.2	0.0	10.6	7.9	8.0	44.6	(1.1)
12-31-2023	3,093	1.1	0.0	74.1	0.0	0.0	10.1	8.2	6.5	49.3	27.6
12-31-2024	2,814	1.0	0.0	68.9	0.0	0.0	10.0	7.6	12.4	39.0	48.3
12-31-2025	2,500	0.9	0.0	62.6	0.0	0.0	9.8	11.1	10.4	31.3	63.4
12-31-2026	2,163	0.8	0.0	55.4	0.0	0.0	9.6	7.8	9.5	28.6	75.9
12-31-2027	1,903	0.7	0.0	49.8	0.0	0.0	9.4	7.0	8.4	25.1	85.9
12-31-2028	1,701	0.6	0.0	45.5	0.0	0.0	9.3	6.4	7.5	22.4	94.0
12-31-2029	1,545	0.6	0.0	42.2	0.0	0.0	9.3	5.9	6.8	20.3	100.6
12-31-2030	1,424	0.5	0.0	39.8	0.0	0.0	8.5	5.6	6.4	19.3	106.4
12-31-2031	1,268	0.5	0.0	36.2	0.0	0.0	8.4	5.1	5.7	17.0	111.0
12-31-2032	985	0.4	0.0	28.7	0.0	0.0	8.2	4.0	4.1	12.4	114.1
12-31-2033	789	0.3	0.0	23.5	0.0	0.0	8.0	3.3	3.0	9.1	116.1
12-31-2034	632	0.2	0.0	19.2	0.0	0.0	8.0	5.6	1.4	4.3	117.0
12-31-2035	425	0.2	0.0	13.2	0.0	0.0	7.8	1.9	0.9	2.7	117.5
12-31-2036	333	0.1	0.0	10.6	0.0	0.0	7.8	1.5	0.3	1.0	117.7
SUBTOTAL		10.5	0.0	733.8	97.2	0.0	149.0	92.2	98.8	296.6	117.7
REMAINING		0.0	0.0	0.0	0.0	23.7	0.0	0.0	0.0	(23.7)	114.1
TOTAL 21 YRS		10.5	0.0	733.8	97.2	23.7	149.0	92.2	98.8	272.9	114.1
CUM PROD		0.0	0.0								
ULTIMATE		10.5	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE	
FOR 8 PCT, PRESENT WORTH MM$	135.5
FOR 15 PCT, PRESENT WORTH MM$	74.1
FOR 20 PCT, PRESENT WORTH MM$	47.5
FOR 25 PCT, PRESENT WORTH MM$	29.5
FOR 30 PCT, PRESENT WORTH MM$	17.0

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

POSSIBLE RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	OIL (MMBBL)	SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2022	70	0.0	0.0	1.6	0.0	0.0	0.1	0.1	0.2	1.2	0.8
12-31-2023	252	0.1	0.0	6.0	0.0	0.0	0.3	0.7	0.9	4.1	3.2
12-31-2024	301	0.1	0.0	7.4	0.0	0.0	0.4	0.8	2.0	4.2	5.4
12-31-2025	424	0.2	0.0	10.6	0.0	0.0	0.5	1.5	2.1	6.4	8.5
12-31-2026	585	0.2	0.0	15.0	0.0	0.0	0.8	2.1	3.0	9.1	12.5
12-31-2027	600	0.2	0.0	15.7	0.0	0.0	0.8	2.2	3.2	9.5	16.3
12-31-2028	578	0.2	0.0	15.5	0.0	0.0	0.8	2.2	3.1	9.4	19.7
12-31-2029	544	0.2	0.0	14.9	0.0	0.0	0.8	3.8	2.6	7.7	22.2
12-31-2030	504	0.2	0.0	14.1	0.0	0.0	1.5	6.5	1.5	4.6	23.6
12-31-2031	524	0.2	0.0	15.0	0.0	0.0	1.6	3.6	2.4	7.3	25.6
12-31-2032	690	0.3	0.0	20.1	0.0	0.0	1.9	4.3	3.5	10.5	28.1
12-31-2033	787	0.3	0.0	23.5	0.0	0.0	2.1	4.7	4.2	12.5	31.0
12-31-2034	860	0.3	0.0	26.2	0.0	0.0	1.3	2.2	5.7	17.0	34.4
12-31-2035	995	0.4	0.0	31.0	0.0	0.0	1.6	5.7	5.9	17.8	37.7
12-31-2036	978	0.4	0.0	31.1	0.0	0.0	1.6	5.6	6.0	18.0	40.8
SUBTOTAL		3.2	0.0	247.6	0.0	0.0	15.9	45.8	46.5	139.4	40.8
REMAINING		2.7	0.0	258.4	0.0	6.3	112.3	38.2	27.0	74.6	52.5
TOTAL 33 YRS		5.8	0.0	506.0	0.0	6.3	128.2	84.1	73.4	214.0	52.5
CUM PROD		0.0	0.0								
ULTIMATE		5.8	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	68.0
FOR 15 PCT, PRESENT WORTH MM$	29.0
FOR 20 PCT, PRESENT WORTH MM$	17.2
FOR 25 PCT, PRESENT WORTH MM$	10.9
FOR 30 PCT, PRESENT WORTH MM$	7.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2017

GROSS (100 PERCENT) INTEREST

PROPERTIES LOCATED IN
WEST KATAKOLO FIELD, OFFSHORE GREECE

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

PERIOD ENDING	GROSS RESERVES AVG OIL RATE (BBL/D)	GROSS RESERVES OIL (MMBBL)	GROSS RESERVES SALES GAS (BCF)	GROSS REVENUE (MM$)	CAPITAL COST (MM$)	ABDMNT COST (MM$)	OPERATING EXPENSE (MM$)	PROD BONUS AND ROYALTY (MM$)	TAXES[1] (MM$)	NET REVENUE (MM$)	CUM P.W. 10% (MM$)
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2019	0	0.0	0.0	0.0	65.9	0.0	0.0	0.0	0.0	(65.9)	(56.2)
12-31-2020	1,313	0.5	0.0	29.5	5.0	0.0	6.0	0.6	2.7	15.1	(44.5)
12-31-2021	2,188	0.8	0.0	50.2	13.0	0.0	8.3	3.1	4.7	21.1	(29.6)
12-31-2022	3,666	1.3	0.0	86.0	13.2	0.0	10.6	8.0	8.2	45.8	(0.3)
12-31-2023	3,345	1.2	0.0	80.2	0.0	0.0	10.5	8.8	7.5	53.4	30.8
12-31-2024	3,115	1.1	0.0	76.3	0.0	0.0	10.4	8.4	14.4	43.2	53.7
12-31-2025	2,924	1.1	0.0	73.2	0.0	0.0	10.3	12.6	12.6	37.8	71.9
12-31-2026	2,748	1.0	0.0	70.4	0.0	0.0	10.3	9.8	12.5	37.6	88.4
12-31-2027	2,503	0.9	0.0	65.5	0.0	0.0	10.2	9.2	11.5	34.6	102.1
12-31-2028	2,279	0.8	0.0	61.0	0.0	0.0	10.1	8.5	10.6	31.7	113.6
12-31-2029	2,090	0.8	0.0	57.1	0.0	0.0	10.0	9.7	9.3	28.0	122.8
12-31-2030	1,928	0.7	0.0	53.9	0.0	0.0	10.0	12.0	8.0	23.9	130.0
12-31-2031	1,791	0.7	0.0	51.1	0.0	0.0	10.0	8.7	8.1	24.3	136.6
12-31-2032	1,675	0.6	0.0	48.9	0.0	0.0	10.0	8.3	7.6	22.9	142.2
12-31-2033	1,576	0.6	0.0	47.0	0.0	0.0	10.1	8.0	7.2	21.7	147.1
12-31-2034	1,492	0.5	0.0	45.4	0.0	0.0	9.3	7.7	7.1	21.3	151.5
12-31-2035	1,420	0.5	0.0	44.2	0.0	0.0	9.3	7.5	6.8	20.5	155.3
12-31-2036	1,311	0.5	0.0	41.7	0.0	0.0	9.4	7.1	6.3	18.9	158.5
SUBTOTAL		13.6	0.0	981.4	97.2	0.0	164.9	138.1	145.3	436.0	158.5
REMAINING		2.7	0.0	258.4	0.0	30.0	112.3	38.2	27.0	50.9	166.6
TOTAL 33 YRS		16.3	0.0	1239.8	97.2	30.0	277.2	176.3	172.3	486.9	166.6
CUM PROD		0.0	0.0								
ULTIMATE		16.3	0.0								

[1] TAXES INCLUDE BOTH CORPORATE AND MUNICIPALITY TAXES.

BASED ON ENERGEAN PRICE AND COST PARAMETERS

PRESENT WORTH PROFILE

FOR 8 PCT, PRESENT WORTH MM$	203.5
FOR 15 PCT, PRESENT WORTH MM$	103.1
FOR 20 PCT, PRESENT WORTH MM$	64.7
FOR 25 PCT, PRESENT WORTH MM$	40.3
FOR 30 PCT, PRESENT WORTH MM$	24.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

TECHNICAL DISCUSSION
WEST KATAKOLO FIELD
OFFSHORE GREECE

1.0 OVERVIEW

West Katakolo Field is located approximately 3.5 kilometers southwest of the southernmost tip of the Katakolo peninsula in a water depth of 250 to 300 meters (m). Figure 1 shows a location map of the area.

West Katakolo Field was discovered in 1981 when the exploration well WK-1 was drilled by the Greek State oil company, Public Petroleum Corporation S.A. (DEP). The structure contains medium crude oil of 29° API overlain by a gas cap in Cretaceous to Eocene carbonates at a depth of approximately -2,300 m true vertical depth subsea (TVDSS). The field was appraised in 1981 and 1982 with the drilling of two additional wells, WK-1A and WK-2. WK-1A found gas and produced at a rate of 11 million cubic feet of gas per day during testing. WK-2 found oil in two zones with test rates between 1,100 and 1,300 barrels of oil per day (BOPD).

Energean Oil & Gas SA (Energean) was awarded the Katakolo license through a tender procedure lasting from July 2012 to May 2014, obtaining operatorship and 100 percent interest in West Katakolo Field. Energean subsequently submitted the field development plan, which includes a phased development based on extended-reach wells from shore. The first phase will consist of two drillwells where the initial well is considered both an appraisal and development well planned for gas injection. This injection well will target the crest of the structure, follow a vertical trajectory to log the gas-oil contact (GOC) and oil-water contact (OWC), and be completed in the gas cap in order to reinject produced gas from the future oil producers. The second well will be a horizontal producer targeting the oil leg. It will be put on production in early 2020, and its performance will be closely monitored for 12 to 18 months. The second development phase, which consists of two additional producers, will be optimized based on field performance. Finally, after depletion of the oil volumes, the gas injector will be converted into a gas producer to blowdown the gas cap. This final development phase is not considered mature enough for economic analysis at this point because of field uncertainties, and gas volumes for West Katakolo Field have been classified as contingent resources.

The duration of the development license for West Katakolo Field is 25 years and started from the execution of the Declaration of Commerciality in August 2016. The duration may be extended for a maximum of two five-year periods that would result in a development license expiry date of August 2051. We have estimated proved undeveloped, probable, and possible oil reserves and contingent gas resources for West Katakolo Field.

1.1 RESERVES

The oil reserves in this report are estimated for the Cretaceous to Eocene carbonate section in West Katakolo Field.

We estimate the gross (100 percent) oil reserves in West Katakolo Field, as of October 31, 2017, to be:

Category	Gross (100%) Oil Reserves (MMBBL)
Proved Undeveloped	6.3
Proved (1P)	6.3

Category	Gross (100%) Oil Reserves (MMBBL)
Probable	4.2
Proved + Probable (2P)	10.5
Possible	5.8
Proved + Probable + Possible (3P)	16.3

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons.

1.2 CONTINGENT RESOURCES

The contingent resources shown in this report for West Katakolo Field are associated with gas cap blowdown, which is regarded as the last phase of development. The contingent resources are contingent upon further appraisal and development of a plan to commercialize the gas resources.

We estimate the unrisked gross (100 percent) contingent gas resources for West Katakolo Field, as of October 31, 2017, to be:

Category	Unrisked Gross (100%) Contingent Gas Resources (BCF)
Low Estimate (1C)	3.7
Best Estimate (2C)	6.2
High Estimate (3C)	9.6

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

2.0 DATA SOURCES

Energean provided a comprehensive technical database for our assessment and allowed full access to its technical staff through email, teleconferences, and a series of meetings held in September 2017. Data provided and utilized in our evaluation include:

- Petrel project with Energean's static characterization consisting of:
  - Historical wells (WK-1, WK-1A, and WK-2) with typical data
    - Well logs
    - Formation tops and bases
    - Directional surveys
  - 3-D seismic data (time) with major horizon and fault interpretations
  - Check shot data
  - Fluid contacts
  - Volumetric calculations

- Computer-processed interpretation (CPI) logs and associated petrophysical interpretation
- Drillstem test (DST) data and analysis for WK-1, WK-1A, and WK-2
- Base case dynamic simulation model
- Pressure-volume-temperature (PVT) analysis for WK-1A gas sample and WK-2 oil sample
- Summaries of fiscal terms
- Field development plan, which includes estimates of operating expenses and capital expenditures
- Estimates of hydrocarbon pricing
- Production sharing contract (PSC) economic model
- Presentations and reports on analog fields to support development strategy and recovery factors

3.0 GEOLOGIC SUMMARY

3.1 OVERVIEW

West Katakolo Field can be found in the Ionian Basin, offshore Greece, in the Ionian Sea. The West Katakolo reservoir is a deep marine carbonate feature of the Lower Cretaceous through Eocene ages and has successfully tested both oil and gas. The productive interval is from the upper section of the Ionian zone. This zone includes Triassic through the Eocene ages. A stratigraphic column is shown in Figure 2.

3.2 TOP CARBONATE RESERVOIR

Mapped on a set of merged 2-D seismic lines, or pseudo 3-D, West Katakolo Field consists of two four-way closed structures, one major and one minor satellite feature to the northwest, which trend northwest-to-southeast and exhibit some internal faulting. The depth structure map for the Top Carbonate is shown in Figure 3. To the east of the field, a Triassic body of diapiric evaporites is present. Formation of these features is due to tectonic events in the basin related to fold and thrust belt development.

The upper section of the Ionian zone reservoir in West Katakolo Field is a succession of carbonates beginning with the Lower Cretaceous Vigla limestones overlain by carbonate turbidites of the Upper Cretaceous. These strata were subsequently covered by pelagic deep marine carbonates of Eocene age, then uplifted and eroded.

Based on the client-provided petrophysical analysis as well as petrophysical properties from nearby analog fields, we estimate that the reservoir net-to-gross ratio (NTG) in West Katakolo Field is close to 100 percent with an average effective porosity of 5 percent and a water saturation range of 50 to 90 percent. Since the reservoir has very low matrix porosity, production flow will be critically enhanced by secondary porosity due to natural fractures and/or karstification. Average gross thickness seen in the wells is 337 m.

The hydrocarbon column is more than 300 m in height. A summary of the basis for our gross rock volume (GRV) calculations is provided in Figure 4. The satellite feature contains oil volumes but is undrilled.

4.0 PETROPHYSICAL SUMMARY

The well log evaluation in West Katakolo Field is particularly challenging given its fractured nature and relatively low matrix porosity. In addition, neither routine nor special core analysis is available to calibrate log interpretations. As a result, we supplemented Energean's petrophysical analysis with DST interpretation results and petrophysical properties observed in analog fields. DST 4 and 5 were of particular importance because their interpretations allowed characterization of the fracture system, in particular fracture porosity. For reference, Energean's log-based petrophysical averages for the main zones in West Katakolo Field are shown in Figure 5. Note that these averages are considered highly uncertain and were not directly used as input into our probabilistic volumetric models; instead, input values were also based on DSTs and analog data as mentioned above.

5.0 RESERVOIR ENGINEERING SUMMARY

Several DSTs were performed in WK-1, WK-1A, and WK-2. These tests are summarized in the following tables:

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Duration (hr)	Oil Rate Average (BOPD)	GOR (SCF/STB)	Gravity (ºAPI)	H_2S (ppm)	Comment
WK-1	1	2,673	2,766	N/A	N/A	N/A	N/A	N/A	Weak flow, reverse circulation with H_2S
WK-2	4	2,557	2,572	6.5	1,100	627	28.0	N/A	
WK-2	5/5A	2,996	3,024	7+	1,300	562	27.6	N/A	

Well	Test	Perforation (m MD) Top	Perforation (m MD) Bottom	Duration (hr)	Gas Rate Average (MMCFD)	Yield (BBL/MMCF)	Specific Gravity	H_2S (mole%)
WK-1A	3	2,996	3,024	5	11	5	0.715	5.4

During DST 4 the oil leg in WK-2 was tested and separator samples were collected and recombined for PVT analysis. The PVT study included constant volume expansion, differential liberation, and separator test experiments. As expected, the tests indicated the oil sample was saturated at reservoir conditions, and thus a gas cap was present. During DST 3, the gas cap in WK-1A was tested and separator samples were collected and recombined. The PVT study included constant composition expansion and constant volume depletion. It was determined that the gas cap gas was very dry with only negligible liquid condensation. The following observations summarize the PVT analyses:

- Initial reservoir pressure is 3,850 psia at -2,550 m TVDSS.
- Both oil and gas were deemed sour, with hydrogen sulfide (H_2S) concentrations between 5 and 11 mole percent.
- Crude density is 23° API and gas cap gas gravity is 0.72.
- Reservoir temperature is approximately 150°F.

- Oil formation volume factor (FVF) at initial pressure is 1.28 reservoir barrels per stock tank barrel (RB/STB).

- Gas expansion factor at initial pressure is 225 standard cubic feet per reservoir cubic feet.

West Katakolo Field will have a phased development plan. The first phase will consist of two extended-reach wells to be drilled in late 2019. The first well, which will serve both as an appraisal and development well, will target the crest of the structure and follow a vertical trajectory to log the GOC and OWC. This well will be completed in the gas cap to reinject produced gas from the oil producers. The next well to be drilled will be a horizontal producer, which will be completed in the oil leg. This well will be put on production at a rate of 1,500 BOPD in January 2020. Its performance will be closely monitored for 12 to 18 months to refine oil-in-place estimates and reservoir drive mechanism. In addition, this early performance should shed light on the porosity and permeability of the fracture system. The second phase, which will consist of two additional horizontal producers, will be optimized based on these findings. One new well will be drilled in early 2021 and put on production around June 2021 with the other well drilled and put on production in 2022. At this point, oil rate per well will be set near 1,000 BOPD to minimize pressure drawdown and prevent gas and water coning. Field production is expected to remain near the plateau rate of 3,000 BOPD until water breakthrough occurs. The last phase of development will follow the oil depletion and consist of converting the gas injector into a gas producer to blowdown the gas cap. The gas cap blowdown project is not mature enough for economic analysis and is regarded as contingent resources at this time.

5.1 RESERVES AND RESOURCES DETERMINATION

Two probabilistic spreadsheet models were constructed. The first model estimated original oil-in-place and gross (100 percent) technically recoverable volumes associated with oil reserves. The second model estimated original gas-in-place and gross (100 percent) technically recoverable volumes associated with contingent gas resources. We determined the type of distribution and input values for the various volumetric parameters separately for the matrix rock and the fractures system.

GRV was input as a lognormal distribution with 90 percent confidence level (P90) and 50 percent confidence level (P50) input values. The P50 value was based on our mapping of the West Katakolo structure. The P90 was defined as 90 percent of the P50 value. Oil and gas volumes were based on a GOC and an OWC of -2,465 and -2,594 m TVDSS, respectively. Porosity, NTG, and hydrocarbon saturation were assigned triangular distributions with minimum, most likely, and maximum input values based on the petrophysical analysis previously described. Oil and gas FVFs, as well as recovery factors, were also modeled as triangular distributions. FVF input values were determined from our review of the PVT reports. Recovery factor inputs were based on the provided dynamic model and analog field data.

To improve characterization of West Katakolo future performance, a detailed review of Energean's dual porosity simulation model was performed. Model input assumptions were found reasonable, and forecasts were leveraged to create flowstreams. Unfortunately, only one subsurface realization was evaluated, which does not capture performance uncertainty. To mitigate this limitation, we leveraged performance of analog fractured fields with low matrix porosity. We observed a wide range of combined matrix and fracture recovery factors ranging from 8 to 60 percent, with a median of 30 percent. We found that the West Katakolo fracture system compared favorably with most of them with similar or slightly higher porosities. In addition, Energean's development plan to drill horizontal wells to maximize reservoir contact and limit pressure drawdown provided significant flexibility to maximize recovery. As a result, good recovery factors ranging from 5 to 15 percent were used for the matrix and 85 to 95 percent were used for the fracture system. Overall, West Katakolo Field recovery factor is estimated at approximately 31 percent.

All volumetric input parameters are summarized in Figures 6 and 7. The resulting original hydrocarbons-in-place and gross (100 percent) technically recoverable volumes calculated in the probabilistic models are summarized in Figures 8 and 9.

6.0 ECONOMICS OVERVIEW

Economics have been run for West Katakolo Field oil reserves. The Netherland, Sewell & Associates, Inc. (NSAI) proprietary economics program was used to forecast oil production by well and reserves category. The oil flowstreams were then included in a cash flow model that incorporated operating costs, capital costs, and fiscal terms. The cash flow economics model used for this area is a spreadsheet model that was developed by Energean. We reviewed and adjusted the model as necessary and used it to calculate net reserves and future net revenue to the Energean interest.

West Katakolo Field is located offshore in approximately 250 to 300 m of water and will be developed from onshore through extended-reach drilling. Produced fluids will be separated onshore, with the oil being prepared for sales by removing the H_2S; treated oil will be sent via a subsea pipeline to a floating, storage, and offloading vessel moored 500 m from the onshore facilities. Water will be sent to a dedicated processing facility, which could be Energean's produced water treatment unit in Kavala or a nearby waste water treatment plant. Produced gas will be reinjected into the reservoir.

As requested, this report has been prepared using oil price parameters specified by Energean. Oil prices are based on October 31, 2017, Dated Brent oil prices and assume the same differentials as the Prinos and South Kavala development area. These differentials are based on contractual deductions to the Dated Brent price along with a historical average differential of the Urals oil price to the Dated Brent oil price from the period December 2016 through November 2017. Oil prices also include adjustments for anticipated API gravity produced from the field and a transportation charge of $3.00 per barrel based on estimates Energean received from shipping companies. Oil prices are escalated 2 percent on January 1 of each year throughout the lives of the properties for inflation.

Operating expenses used in this report are estimated based on operating expense records and budgets of Energean. Costs are included for fixed field costs and electricity costs. Fixed field costs are required to operate the onshore facility and are estimated to initially be $3.6 million per year; these costs increase by $0.75 million in July 2021 when additional production capacity is required. Electricity costs include a power consumption factor of 0.01525 megawatt hour (MWh) per barrel per day of daily production capacity, which Energean estimated using a facility modeling program; this factor is multiplied by the daily production capacity and by the electricity purchase price of $66.00 per MWh, which is based on the 12-month average electricity cost charged to Energean from September 2016 through August 2017 in the Prinos and South Kavala development area. As requested, operating expenses are escalated 2 percent on January 1 of each year throughout the lives of the properties for inflation. Details of our operating expense estimates by expense category, before escalation, are shown in Figure 10.

Capital expenditures used in this report were provided by Energean and are based on budgeted expenditures and authorizations for expenditure. Initial facility installation costs are $34.2 million, with an additional $4.7 million to be spent in 2020 for the expansion of production capacity. Drilling costs of $53.2 million are included to drill 3 producers and 1 injector. As requested, $15.9 million is included for abandonment of the wells and production facilities at the economic limit of the field. Also as requested, capital expenditures and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure for inflation. Details of our capital expenditure estimates, before escalation, are shown in Figure 11.

Basic fiscal terms and economic parameters used in the Energean economics model are shown in the following table:

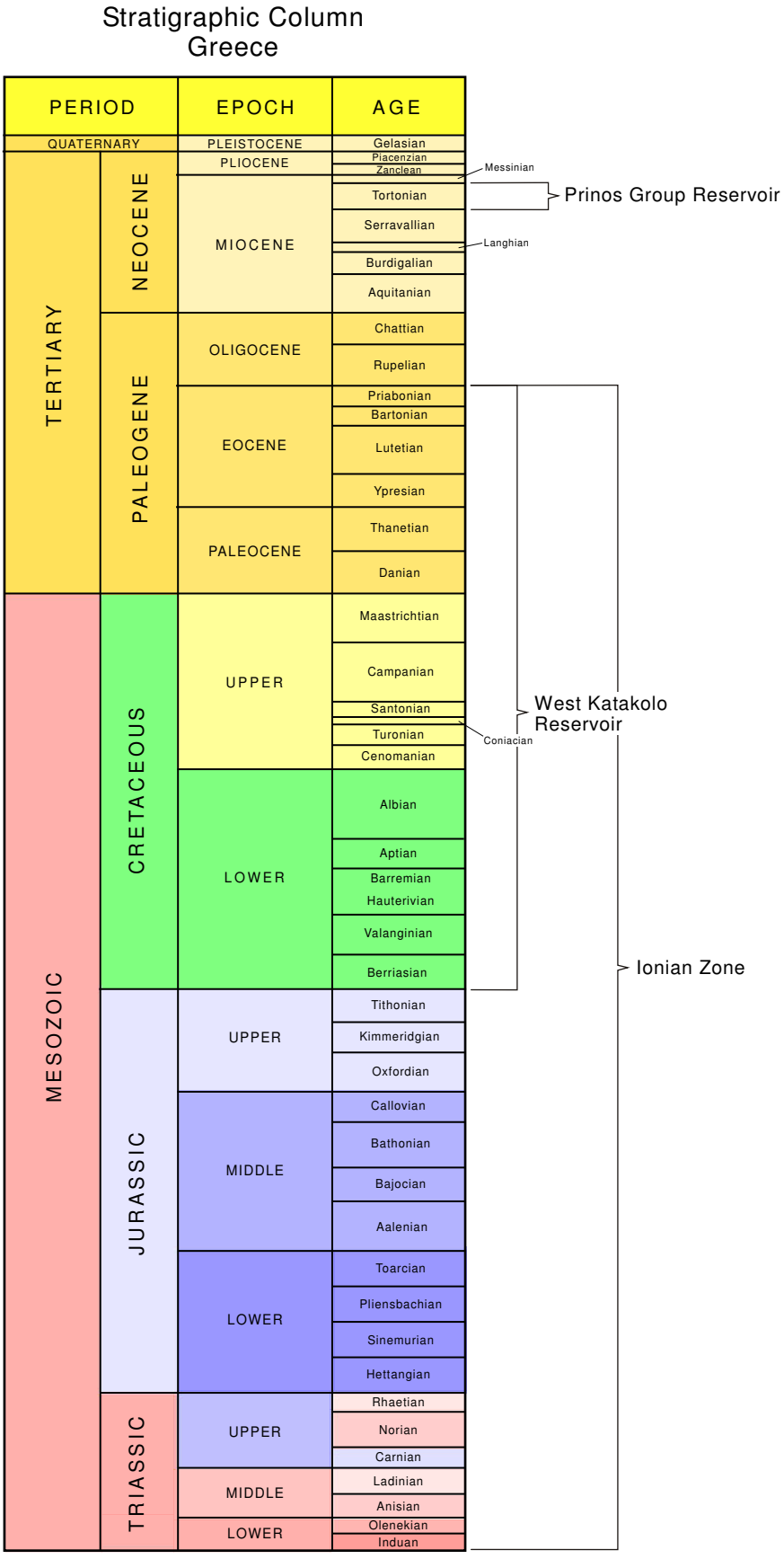
Fiscal Terms	
Contract Type	PSC
Operator	Energean
First Production (estimated)	January 1, 2020

Fiscal Terms	
Interest (%)	100
Production-based Sliding-scale Royalty (%)	2 to 20
Corporate Tax (%)	20
Municipality Tax (%)	5
Oil Price Adjustment ($/Barrel)	-7.44

Summary projections of estimated reserves and future net revenue to the Energean interest are shown in Tables I through VI located prior to this technical discussion.

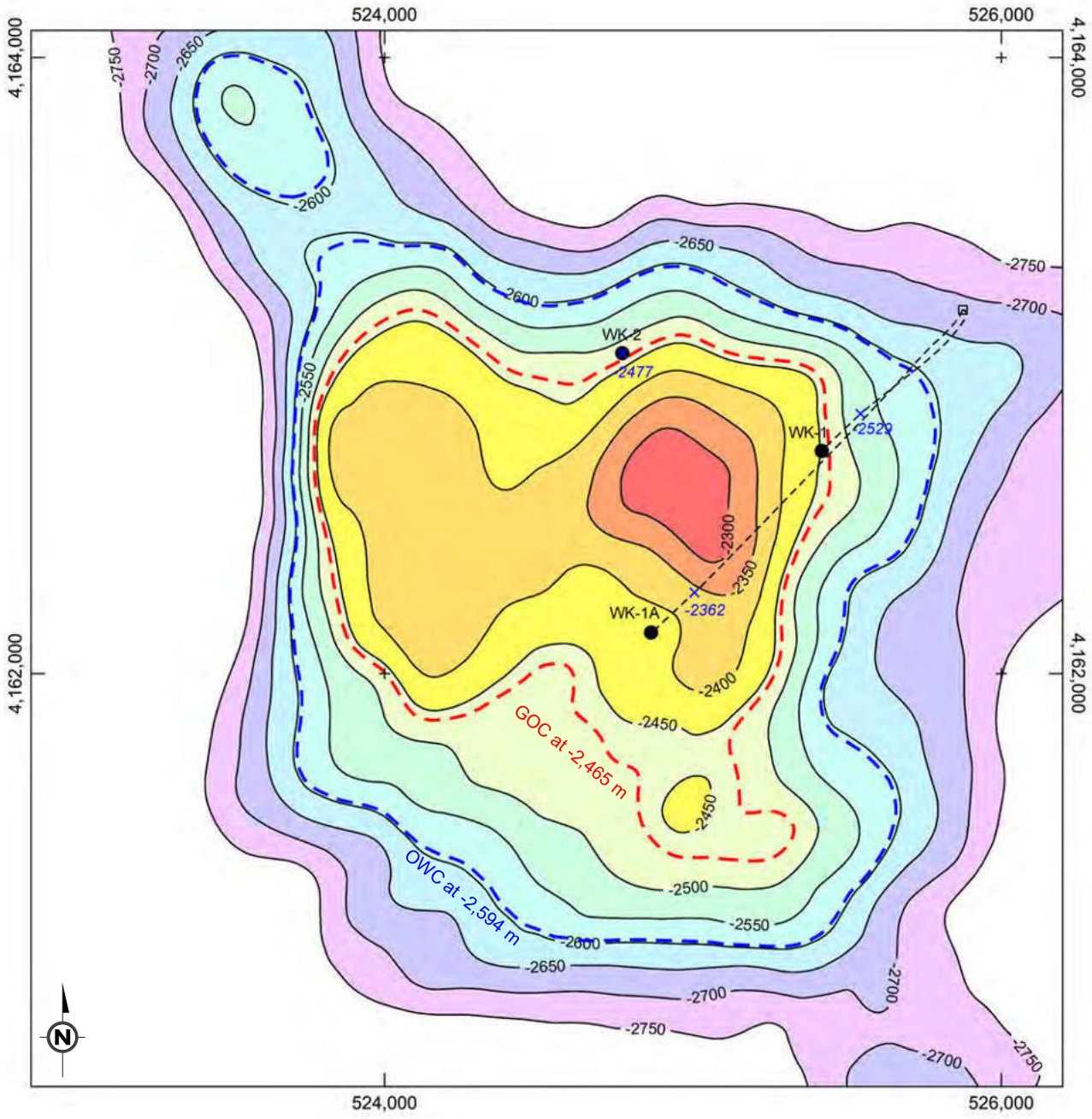


All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Figure 1



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2



West Katakolo Field
Offshore Greece

Depth Structure
Top Carbonate

Contour Interval: 50 m

SCALE IN METERS
0 250 500 750 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

NETHERLAND, SEWELL & ASSOCIATES, INC.

GROSS ROCK VOLUME BASIS
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Reservoir	Category	Low Estimate Case	Best Estimate Case	Distribution Type
Top Carbonate	1P	Best Estimate - 10%	NSAI mapping based on a GOC at -2,465 m TVDSS and an OWC at -2,594 m TVDSS	Lognormal

Figure 4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

ENERGEAN PETROPHYSICAL SUMMARY
WEST KATAKOLO FIELD, OFFSHORE GREECE

Well/Zone	Depth (m MD) Top	Depth (m MD) Base	Depth (m TVDSS) Top	Depth (m TVDSS) Base	Gross Interval (m)	Net Pay (m)	NTG (Decimal)	Porosity (Decimal)	Water Saturation (Decimal)
WK-1									
Eocene	2,704	2,908	-2,528	-2,704	176	176	1.00	0.04	0.97
Upper Senonian	2,908	2,934	-2,704	-2,727	23	23	1.00	0.05	1.00
Lower Senonian	2,934	2,990	-2,727	-2,778	51	51	1.00	0.08	0.99
Vigla	2,990	3,032	-2,778	-2,817	39	39	1.00	0.08	0.83
WK-1A									
Eocene	2,933	2,937	-2,362	-2,366	3	3	1.00	0.05	0.74
Upper Senonian (Gas)	2,937	3,071	-2,366	-2,465	99	99	1.00	0.03	0.75
Upper Senonian (Oil)	3,071	3,084	-2,465	-2,475	10	10	1.00	0.02	0.73
Lower Senonian	3,084	3,126	-2,475	-2,506	31	31	1.00	0.05	0.86
Vigla	3,126	3,222	-2,506	-2,577	71	71	1.00	0.03	0.80
WK-2									
Upper Senonian	2,499	2,518	-2,484	-2,504	20	20	1.00	0.08	0.82
Lower Senonian	2,518	2,572	-2,504	-2,557	54	54	1.00	0.04	0.82
Vigla (Oil)	2,572	2,608	-2,557	-2,594	36	36	1.00	0.03	0.88
Vigla (Water)	2,608	2,674	-2,594	-2,659	66	66	1.00	0.03	0.90
Upper/Middle Jurassic	2,674	2,870	-2,659	-2,855	196	166	0.85	0.02	0.83
Jurassic Dolomitic	2,870	3,006	-2,855	-2,991	136	136	1.00	0.08	0.95

Note: Petrophysical results shown are from Energean's West Katakolo Field Development Plan.

Figure 5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS ASSOCIATED WITH OIL RESERVES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Porosity System	Category[1]	Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
		P90	P50	P10	Min	Most Likely	Max	Min	Most Likely	Max
Matrix	1P	273,738	304,153	N/A	0.98	0.99	1.00	0.0300	0.0500	0.0700
Fractures	1P	273,738	304,153	N/A	0.98	0.99	1.00	0.0015	0.0039	0.0100

Porosity System	Category[1]	Hydrocarbon Saturation (Decimal)			Formation Volume Factor (RB/STB)			Recovery Factor (Decimal)		
		Min	Most Likely	Max	Min	Most Likely	Max	Min	Most Likely	Max
Matrix	1P	0.10	0.25	0.50	1.25	1.28	1.31	0.05	0.10	0.15
Fractures	1P	0.98	0.99	1.00	1.25	1.28	1.31	0.85	0.90	0.95

[1] For porosity systems categorized as 1P, we have estimated 1P, 2P, and 3P technically recoverable volumes associated with reserves.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS
ASSOCIATED WITH CONTINGENT GAS RESOURCES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Porosity System	Category[1]	Gross Rock Volume (Acre-Feet)			Net-to-Gross Ratio (Decimal)			Porosity (Decimal)		
		P90	P50	P10	Min	Most Likely	Max	Min	Most Likely	Max
Matrix	1C	91,384	106,660	N/A	0.98	0.99	1.00	0.0300	0.0500	0.0700
Fractures	1C	91,384	106,660	N/A	0.98	0.99	1.00	0.0015	0.0039	0.0100

Porosity System	Category[1]	Gas Saturation (Decimal)			Formation Volume Factor (SCF/ft^3)			Gas Recovery Factor (Decimal)		
		Min	Most Likely	Max	Min	Most Likely	Max	Min	Most Likely	Max
Matrix	1C	0.10	0.30	0.50	215	225	235	0.05	0.10	0.15
Fractures	1C	0.98	0.99	1.00	215	225	235	0.85	0.90	0.95

[1] For porosity systems categorized as 1C, we have estimated 1C, 2C, and 3C technically recoverable volumes associated with contingent resources.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL OIL-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH OIL RESERVES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Porosity System	Original Oil-in-Place (MMBBL)			Gross (100%) Technically Recoverable Oil Volumes[1] (MMBBL)			Recovery Factor[2] (%)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Matrix	13.4	25.0	41.6	1.1	2.5	4.9	8	10	12
Fractures	5.2	8.9	14.3	4.6	8.0	13.1	88	90	91
Arithmetic Sum[3]	18.6	33.9	56.0	5.6	10.5	18.0	30	31	32
Probabilistic Sum	21.2	34.3	52.6	6.4	10.7	16.8	30	31	32

(1) Technically recoverable volumes associated with reserves are prior to application of economics. The portion of the volumes that are economic are classified as reserves.

(2) Recovery Factor is calculated by dividing unrounded Gross (100 Percent) Technically Recoverable Oil Volumes by unrounded Original Oil-in-Place. See Volumetric Input Parameters for recovery factor input distributions.

(3) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF ORIGINAL GAS-IN-PLACE AND
GROSS (100 PERCENT) TECHNICALLY RECOVERABLE VOLUMES
ASSOCIATED WITH CONTINGENT GAS RESOURCES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Porosity System	Original Gas-in-Place (BCF)			Gross (100%) Technically Recoverable Gas Volumes[1] (BCF)			Recovery Factor[2] (%)		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Matrix	8.2	15.1	24.8	0.7	1.5	2.9	8	10	12
Fractures	2.9	5.0	8.1	2.6	4.5	7.4	89	90	91
Arithmetic Sum[3]	11.2	20.2	32.9	3.2	6.0	10.3	29	30	31
Probabilistic Sum	12.8	20.6	30.8	3.7	6.2	9.6	29	30	31

Note: In-place volumes are reported at surface conditions.

(1) Because economic analysis has not been performed on these volumes, contingent gas resources for West Katakolo Field are equal to the technically recoverable volumes shown.

(2) Recovery Factor is calculated by dividing unrounded gross (100 percent) technically recoverable volumes by unrounded original in-place volumes. See Volumetric Input Parameters for recovery factor input distributions.

(3) Arithmetic sums do not include the portfolio effect that might result from statistical aggregation and may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

GROSS ANNUAL OPERATING EXPENSE ESTIMATES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

Category	Gross Fixed Field Expenses (MM$)						
	2017[1]	2018	2019	2020	2021	2022	Thereafter
Operations and Maintenance	0.0	0.0	0.0	3.6	4.0	4.4	4.4
Electricity Purchase	0.0	0.0	0.0	0.6	1.3	1.3	1.3[2]
Total	0.0	0.0	0.0	4.2	5.2	5.6	5.6[2]

Note: Costs shown are prior to escalation for inflation.

(1) November and December 2017 only.

(2) Electricity costs are dependent on the field oil production rate. For rates below 1,500 BOPD, estimated costs are $0.63 million per year, and for rates at or above 1,500 BOPD, estimated costs are $1.27 million per year.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

GROSS CAPITAL EXPENDITURE ESTIMATES
WEST KATAKOLO FIELD, OFFSHORE GREECE
AS OF OCTOBER 31, 2017

	Gross Capital Expenditures (MM$)							
Category	2017[1]	2018	2019	2020	2021	2022	Thereafter	Total
Facilities	0.0	0.0	34.2	4.7	0.0	0.0	0.0	38.9
Drilling	0.0	0.0	29.2	0.0	12.0	12.0	0.0	53.2
Abandonment[2]	0.0	0.0	0.0	0.0	0.0	0.0	15.9	15.9
Total	0.0	0.0	63.4	4.7	12.0	12.0	15.9	108.0
Number of Wells Drilled	0	0	2	0	1	1	0	4

Note: Costs shown are prior to escalation for inflation.

(1) November and December 2017 only.
(2) Field abandonment occurs in 2030, 2037, and 2049 in our 1P, 2P, and 3P reserves cases, respectively.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

נספח 2

דו"ח שנתי לשנה שהסתיימה ביום 31 בדצמבר 2017 ("דו"ח שנתי 2017")



A new era...

Energean Oil & Gas plc
Annual Report 2017

ENERGEAN
OIL & GAS



A new era...

...in our growth story

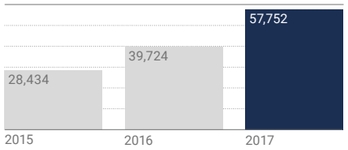
2018 is set to be a very exciting chapter in our growth story. We are entering a new stage in our development towards becoming the leading independent oil and gas E&P company in the Eastern Mediterranean. In March this year, we completed a successful IPO raising US$460 million for investment in our business, principally our Karish and Tanin fields, offshore Israel.

Our long-term strategy is to create sustainable growth by leveraging the Group's experience and expertise in identifying, acquiring, developing and operating oil and gas assets in this region, and by meeting the economic, social and environmental challenges of what is a fast-growing energy market.

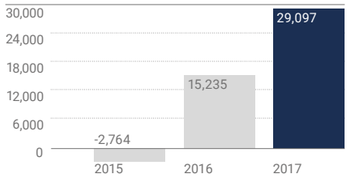
Key highlights

Financial

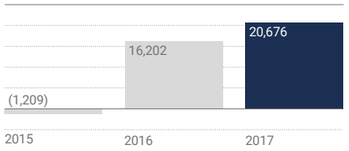
Revenue
US$ '000s



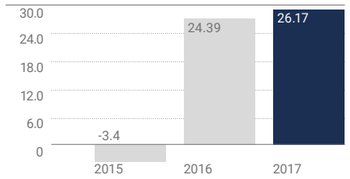
Cash flow from operating activities
US$ '000s



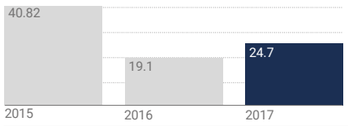
Adjusted EBITDAX[1]
US$ '000s



Gearing ratio
(%)



Cost of oil production per barrel
US$/bbl



Operational

Average daily production
2,803 bopd
2016: 3,490 bopd

2P reserves
51 MMbbls oil
2016: 41 MMbbls oil

2C resources
1.2 Tcf gas[1]
2016: 1.05 Tcf
[1] 50% of the Group working interest

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Leading E&P player in the Eastern Mediterranean

We are an independent oil and gas E&P company focused on developing resources in the Eastern Mediterranean, where we hold 13 licences and operate assets with a production track record of more than 37 years.

Energean's operations began when the Group acquired the Prinos licences, offshore North East Greece, in 2007. At the time, these licences contained 2 mmboe of audited 2P reserves. Ten years later, the Group has built up a balanced portfolio of producing and development assets, containing a total of 51 MMbbls of oil 2P reserves in Greece; 1.2 Tcf of natural gas 2C resources in Israel; and 39.4 MMbbls of oil 2C resources in both countries. Energean is committed to realising the significant growth potential of its development and exploration projects, such as the Karish and Tanin fields, offshore Israel, and other licence blocks in Greece and Montenegro.

4
Countries*

37
Years of experience as an offshore operator

1.2
Tcf gas 2C resources

13
E&P licences

393
Highly skilled employees**

39.4
MMbbls oil 2C resources

17
Active wells

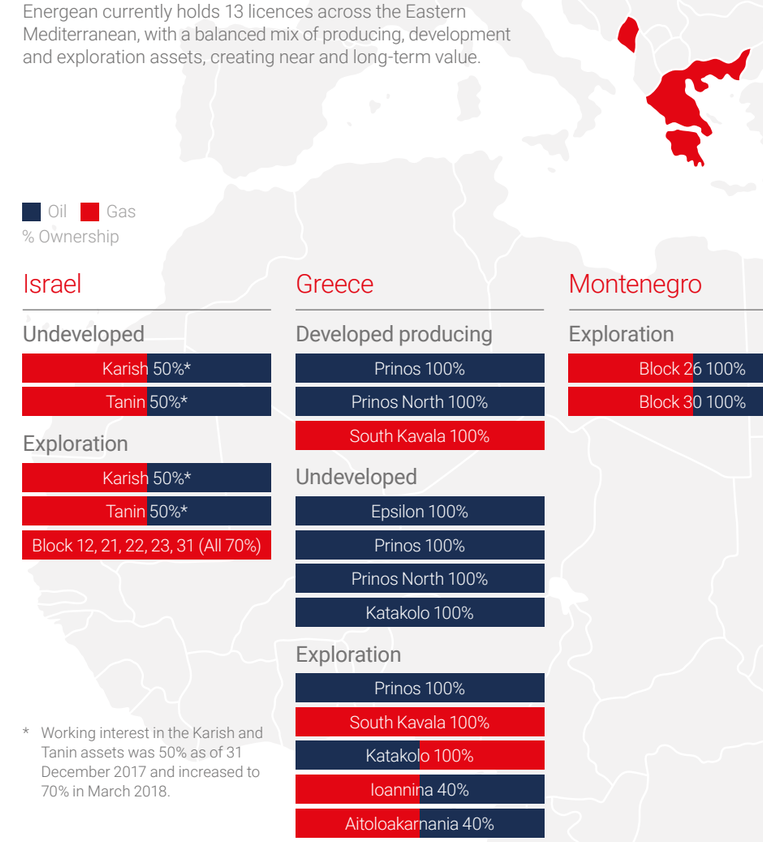
51
MMbbls 2P reserves

12
Israeli GSPAs of total contracted volume up to 74 BCM

* Offices in the UK, Israel, Greece, Cyprus, Egypt and Montenegro
** Excluding sub-contractors

Where we operate

Energean currently holds 13 licences across the Eastern Mediterranean, with a balanced mix of producing, development and exploration assets, creating near and long-term value.



Oil Gas
% Ownership

Israel

Undeveloped
- Karish 50%*
- Tanin 50%*

Exploration
- Karish 50%*
- Tanin 50%*
- Block 12, 21, 22, 23, 31 (All 70%)

Greece

Developed producing
- Prinos 100%
- Prinos North 100%
- South Kavala 100%

Undeveloped
- Epsilon 100%
- Prinos 100%
- Prinos North 100%
- Katakolo 100%

Exploration
- Prinos 100%
- South Kavala 100%
- Katakolo 100%
- Ioannina 40%
- Aitoloakarnania 40%

Montenegro

Exploration
- Block 26 100%
- Block 30 100%

* Working interest in the Karish and Tanin assets was 50% as of 31 December 2017 and increased to 70% in March 2018.

Our History

2007 Aegean Energy S.A. announces the purchase of 100% of Eurotech's shares, majority shareholder of Kavala Oil S.A.

2008 Aegean Energy initiates a new development plan for Prinos North and Epsilon fields

2010 Aegean Energy S.A. changes its name to Energean Oil & Gas

2013 Aegean Energy S.A. achieves extension of the concession licence for the Prinos oil field area

2013 Multi-year offtake agreement signed between BP and Energean Oil & Gas for the entire oil production from Prinos

2013 Third Point invests in Energean as equity supporter

2014 Energean purchases its own drilling rig

2015 Energean completes 3D seismic survey in the Prinos Oil Field

2016 Energean acquires 100% interest in Karish & Tanin fields, offshore Israel, from Delek Drilling and Avner

2016 Secured US$75m EBRD RBL facility as well as agreed US$20m finance for exploration assets

2016 Agreed to investment in Energean Israel from Kerogen Capital

2017 Energean is awarded two offshore blocks in the Adriatic (Montenegro)

2017 Repsol farms-in to Energean's Ioannina and Aitoloakarnania Blocks, onshore Western Greece

2018 Energean IPO raises US$460 million on the LSE

Energean signs US$1.275 billion financing to develop Karish field

2018 Signed extended and updated US$180m RBL Senior facility in January 2018

Embarking on an exciting chapter in our history



Simon Heale
Chairman

Our portfolio offers both near-term value delivery, significant mid-term value and longer-term potential upside from which we are well-positioned to benefit.

Key Board agenda focus for 2018

- Health & safety
- Corporate culture
- Delivering on key project milestones for Karish and Tanin
- Maximising production through the Prinos development programme
- Maintaining capital discipline
- Compliance with Corporate Governance Code
- Progressing our CSR programme

Dear Shareholder,

I was delighted to join the Board of Energean as Chairman in July 2017. Since then, I have been impressed by how much the Company has achieved in a few months in running the day-to-day business, making significant progress on both the Karish and Tanin project and the Prinos Basin expansion, and, most recently, becoming a Premium Listed Company on the London Stock Exchange ('LSE') in March 2018, the first significant European oil and gas E&P listing since 2014 and the largest ever primary raise for a Premium-Listed E&P company on the LSE.

These achievements are driven by a strong corporate culture and an equally strong health, safety and environmental ('HSE') focus, backed by a professional management team. The staff of Energean are determined to make the Company the leading independent operator in the Eastern Mediterranean.

Our Board and Management are focused on this goal and are committed to achieving it while delivering value for shareholders and stakeholders.

Our Board and governance

Our Board was chosen to ensure that, as a fast-growing public Company, Energean demonstrates best practice governance standards and provides sound stewardship.

We are fortunate to have deep sector, financial, HSE and capital markets expertise on the Board to guide the Company going forward.

As a Premium Listed Company, the Board will comply with the UK Corporate Governance Code. We have appointed audit, risk, governance and remuneration committees to safeguard shareholders' interests and provide a strong governance framework.

Our people

The depth and breadth of skills across our technical, engineering, geological and financial teams and wider workforce, enables us to be agile in our decision making and to deliver our growth projects while remaining open to future opportunities.

Energean's management team has over 200 years' combined experience in the oil and gas industry encompassing a broad range of projects, asset types (including offshore, shallow and deepwater), and exploration and production technology. Our senior management team are also significant shareholders in the business and are therefore fully aligned with the interests of other shareholders.

All the Company's staff have worked with dedication and commitment over the last few months to deliver the IPO and our new projects. I am very grateful to them all for everything they have done.

Dividend policy

We are in a growth phase and our investors have bought into an ambitious, fast-moving Company in an exciting region. We therefore do not anticipate that the Company will pay a dividend until the Karish and Tanin development is completed. Until then, any earnings will be reinvested in developing the businesses of the Group. The Board will review how it provides returns to shareholders regularly and will take a prudent approach that has regard to the level of profit generated by the Group's operations and the funding requirements for our operations and exploration and development programmes.

The future

We have a clear and substantially de-risked pathway to production growth ahead of us with the Karish and Tanin, Prinos Basin and Katakolo development programmes.

Our portfolio offers both near-term value delivery, significant mid-term value and longer-term potential upside from which we are well-positioned to benefit. I look forward to reporting on further progress over the coming year.

Simon Heale
Chairman

A sustainable growth story



Mathios Rigas
Chief Executive Officer

We are embarking on a new era for the Company and for the emerging oil and gas industry in the Eastern Mediterranean.

A new era...

When Energean was established in 2007, it was with a clear vision to build the leading independent E&P company in the Eastern Mediterranean. We saw a region which had been overlooked and under-exploited by the international oil and gas majors, and one that would inevitably need more gas development to cater for growing demand for cleaner energy in the surrounding states.

The past decade has been one of considerable growth, learning, investment and achievement for Energean.

We are embarking on a new era for the Company and for the emerging oil and gas industry in the Eastern Mediterranean – a region which could soon become a globally significant gas hub.

Since 2008, we have steadily expanded our operating footprint from one country to four; from two licences in Greece to 13 licences in the Eastern Mediterranean; and from 2 mmboe (2P) reserves in our Prinos licence to 51 mmboe (2P) reserves and 339 mmboe (2C) resources across our portfolio. In a very short period, we have taken the prospective Karish and Tanin gas fields, offshore Israel, from acquisition in December 2016, through a Field Development Plan (FDP) and financing, to a Final Investment Decision (FID). This is a remarkable achievement, of which we are very proud.

Advancing our flagship project: Karish and Tanin

Having signed 12 Long Term Gas Sales & Purchase Agreements with the leading Independent Power Producers (IPPs) and industrial companies in Israel, we have secured substantial revenues underpinning Energean's performance over the next two decades and will meet the Israeli Government's objectives of encouraging competition in the domestic Gas market and improving supply security from 2021, when we plan to produce first gas from Karish.

Delivering the project on time and on budget has been affirmed through an Engineering, Procurement, Construction, Installation & Commissioning (EPCIC) turnkey contract, signed with TechnipFMC, protecting our shareholders against risks of delays and cost overruns.

We have attained the necessary financing to complete our major development projects in Israel and Greece, which allowed us to take FIDs on both the Karish and Tanin project in Israel and our Epsilon development project in Greece.





Post-period developments

2017 has provided us with a platform to move quickly, and since the reporting period, we have delivered on these key strategic milestones:

- Proceeded with Final Investment Decision ('FID') on the Karish and Tanin project on schedule
- Signed the US$1.275 billion senior credit facility for the Karish and Tanin project
- Completed the successful Premium Listing on the London Stock Exchange, raising US$460 million through the Global Offer – the first significant European oil and gas E&P listing since 2014 and the largest ever primary raise for a Premium-Listed E&P company on the London Stock Exchange
- Signed a US$180 million RBL facility with the European Bank for Reconstruction and Development ('EBRD') and other international institutions to fund the development programme for the Prinos, Prinos North and Epsilon oil fields
- Completed the subscription of additional shares in Energean Israel in March 2018 for the amount of US$266.7 million resulting in the Group increasing its holding in Energean Israel to 70%
- Awarded TechnipFMC an integrated Engineering, Procurement, Construction and Installation contract for the Karish full field development, covering the design and installation of the complete subsea system, Floating Production Storage and Offloading unit (FPSO), designed to allow the subsequent tie back of Tanin field, the pipeline system, and the onshore pipeline and valve station at the receiving station
- Appointed Stena Drilling to commence a three development well drilling programme in 2019
- Signed extension to the BP Offtake Agreement from July 2021 to November 2025
- Successfully completed the c4km extended reach well in Prinos North field ahead of schedule in late March. The well is currently producing approximately 1,000bpd on a 41% choke
- Production averaged 3,673 bopd in Q1 2018, an increase of 31.6% year-on-year (Q1 2017: 2,790 bopd) and 7.9% quarter-on-quarter (Q4 2017: 3,405 bopd)
- Progressed plans for a secondary listing on the Tel Aviv Stock Exchange in Israel, on which the Group will be filing an application in the near future

A sustainable growth story

Successful IPO and project financing

Energean's Premium Listing on the London Stock Exchange in March 2018, raising US$460 million, was a landmark accomplishment for the Company. It has effectively reopened the upstream IPO market after four years of relative stagnation and is a strong indicator that positive sentiment is returning to the London oil and gas sector.

Signing the US$1.275 billion Facility Agreement in the same month was a key milestone in financing the development of the Karish and Tanin project and testament to the confidence placed in us by leading international banks.

Our investment proposition to the London market attracted substantial institutional interest, despite challenging market conditions. This proposition is characterised by the quality of our asset portfolio, our strategic position in the Eastern Mediterranean, our offshore experience and our management's track record of value creation.

Our priority now is to deliver significant growth in our first year as a listed business.

Our strategy

Our aim is to maximise production, reserves and cash flow from our existing low-cost production base, while pursuing sustainable growth and returns through active development and exploration programmes in the Eastern Mediterranean. We will achieve this while maintaining a disciplined financial framework and a conservative balance sheet. This strategy is underpinned by our key competitive strengths:

- We are an experienced offshore operator, operating the majority of assets in our portfolio
- We are well-positioned as an independent, Eastern Mediterranean E&P to move quickly in an increasingly active region
- We have a track record of value creation through timely acquisitions and efficient development
- We have the depth and diversity across a series of assets at various stages of development to position us as a full-cycle, sustainable business
- We have an experienced management team, with an international oil industry track record, who are significantly invested in Energean
- We have a strong health and safety track record
- We have world class industry partners such as TechnipFMC, BP and Repsol and strong financial capacity

1 Maximising output and cash flow from our producing assets

The Prinos and Prinos North oil fields, offshore North Eastern Greece, are low-cost producing assets that have already delivered 115 million barrels of oil to date. The Prinos Basin licence was acquired in 2007. Since then, we have secured a 25-year licence extension and have increased reserves through the technical reappraisal of the reservoir, with a new 3D campaign undertaken in 2015 as well as further drilling activity enabling us to implement our fully-funded development plan to significantly increase production over the next three years.

Energean's long track record in the Prinos basin, operatorship of the majority of our assets, and low operating costs per barrel, underpins our ability to maximise cash flow from our reserves and resources.

Prinos development programme

In the Prinos Basin, we are delivering an investment plan of approximately US$350 million through 2021, which we expect to significantly increase production over the next few years, tapping the 39.5 MMbbls of discovered 2P oil reserves and 6 Bcf of 2P gas in the Prinos, Prinos North and Epsilon oil fields.

This development plan includes drilling 24 new wells (with eight wells already drilled since December 2015); the construction of an unmanned platform to exploit the Epsilon field adjacent to Prinos; and infill drilling in the existing producing fields.

We regard Prinos as a low-risk development, due to our extensive knowledge and experience of the Basin and its geology, the secured offtake agreement with BP that will fully cover the expected increase in production, and the control we enjoy as operator over the related infrastructure.

2 Developing Karish and Tanin

A material de-risked opportunity

Our most significant undeveloped assets are the Karish and Tanin gas fields located offshore Israel, which we acquired in December 2016 for US$148.5 million and which are set to transform our business over the next few years. The fields have an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of condensate and light oil (contingent 2C resources) .

At the time of acquisition, Karish and Tanin were stranded assets with no gas contracts in place. Along with receiving approval of our FDP from the Israeli government in August, last year we aimed to secure gas sale and purchase agreements with leading industrial companies and power producers in Israel. By December 2017, the Company had secured contracts with 12 leading domestic industrial and independent power producers in Israel for the sale of 61 BCM of gas (up to 74 BCM including the OR gas supply agreement) over a period of 16 years on a weighted average basis. The annual production rate is estimated at approximately 4.2 BCM per year on an ACQ basis (up to 5.1 BCM per year including the OR gas supply agreement). This was 1.2 BCM above the amount required to proceed with FID for Karish and Tanin and reflects the increasing energy demand in Israel.

Currently discovered 2C discounted cash flows from Karish and Tanin equate to an estimated NPV of US$830 million net to Energean (70% working interest (WI)) according to the NSAI CPR. This uplift in value has been realised in the space of 15 months, due to Energean's ability to execute key project milestones quickly and effectively.

The development of the Karish field, which is fully-funded to first gas in 2021, will materially increase the scale of the Group's operations and support Energean's strategy to become a major player in the Eastern Mediterranean gas market. Production from Karish will be solely used to supply Israel. Therefore, these assets are highly strategic for the development of the Israeli energy market and can help to meet increasing Israeli demand, increase market competition and improve security of supply.

We have de-risked the project through a scalable development plan. Our new-build FPSO will allow Energean to develop its assets in the region and will be available to be used as a tie back option for future third party discoveries. The FPSO is currently the only such vessel earmarked for operation in the region, presenting us with an advantage to quickly capitalise on suitable adjacent discoveries.

3 Capitalising on growth opportunities in the Eastern Mediterranean

Katakolo

In addition to the Prinos Basin, we are also advancing the development of Katakolo in Western Greece in 2018, which we received government approval to develop in 2017 and which holds 10.5 MMbbls of 2P oil reserves and 6.2 Bcf of 2C gas resources. On approval of an Environmental and Social Impact Assessment, we expect to take our FID on the project in the second half of 2018, and drill the first pilot well in the second half of 2019. First oil is expected in 2020.

Exploration prospects

Energean has a focused exploration strategy with several exploration prospects in Greece, Montenegro and Israel. Our strategy revolves around identifying and exploring undeveloped areas where we have technical experience of similar geologies to minimise exploration risk. Our exploration portfolio has best estimate unrisked prospective resources of 3.1 Tcf of natural gas and 375.3 MMbbls of liquids.

We deploy a controlled approach to managing exploration risk. This is evidenced in our two onshore Greek exploration assets, Aitoloakarnania and Ioannina, which we recently farmed out to Repsol as operator (60% WI), and who will carry 90% of the exploration costs.

In March 2017, Energean signed a concession contract to explore blocks 26 and 30 offshore Montenegro, which hold best estimate unrisked prospective resources of 1.8 Tcf of natural gas and 143.9 MMbbls of liquids. While the Eastern Adriatic remains substantially underexplored, Western offshore Adriatic has been a prolific hydrocarbon producing province for over 50 years for both oil and gas. We believe Montenegro has significant exploration potential for future oil and gas discoveries and the entry of ENI into the four blocks neighbouring those held by Energean, with significant exploration commitments, is an indication of the area's potential. We plan to begin the 3D seismic acquisition at the end of this year, to be completed in the first half of 2019.

In November 2017, Energean Israel participated in Israel's First Offshore Bid Round, and in December was awarded five licences for blocks 12, 21, 22, 23 and 31. The award of these exploration licences, adjacent to our Karish and Tanin project, further bolsters our exploration portfolio and long-term value potential in the region. Block 12 is on trend with the Karish and Tanin discoveries, presenting an opportunity for low-risk exploration, which could be developed via a tie back to the FPSO.

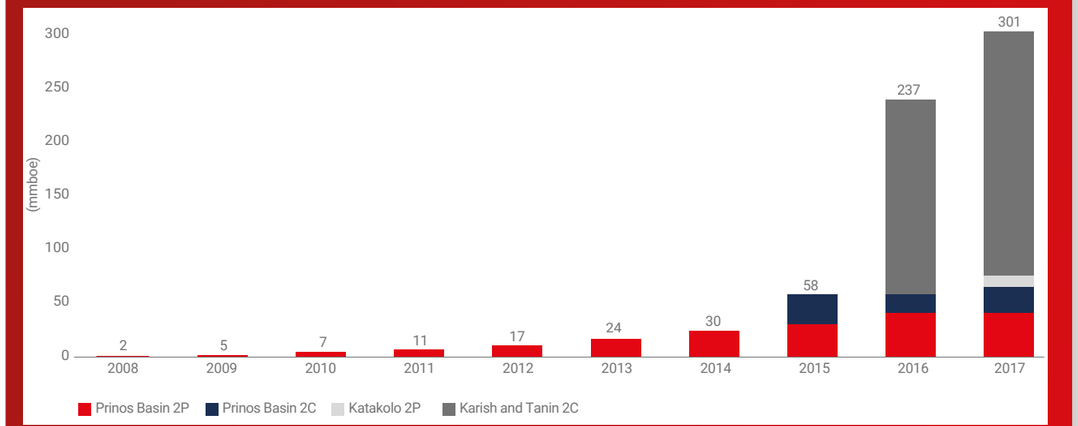
4 Maintaining a disciplined financial framework

We have successfully maintained a conservative balance sheet throughout the commodity down-cycle, through careful management of working capital and low levels of bank debt. We aim to preserve our balance sheet flexibility, alongside disciplined capital deployment, backed by strong cash flow from our producing assets.

As our track record demonstrates, Energean continually assesses ways to create further sustainable value and act upon value-accretive opportunities. We have strict investment criteria for new projects, typically targeting an unlevered internal rate of return of more than 15%. This approach, alongside the Group's production, development and exploration prospects, will underpin Energean's sustainable growth in the future.

A sustainable growth story

Continuous increase in reserves & resources



Health, safety and the environment

We see our health, safety and environmental (HSE) performance as a key aspect of the overall success of our business. We are committed to the highest standards of HSE regarding our employees, contractors, partners, the general public and the mitigation of our environmental impact.

Our experience of operating in environmentally sensitive areas without compromising them is something we are incredibly proud of. Energean's HSE record has been an important factor in our successful bids for licences, including Karish and Tanin.

Energean is the only oil and gas producer in Greece and, together with its predecessor business, has a 37-year track record of operating offshore and onshore assets in environmentally sensitive areas. Energean's experience and conscientious approach towards the management of its assets is a key differentiator in the sector.

As we continue to scale up operations, we will remain focused on our key HSE performance indicators and the safety of our employees. These are key aspects of how we operate as a business and are integral to our culture and engagement with our stakeholders.

Karish & Tanin project milestones 2018

Q2 2018

- Submit Karish Lease Environmental Document to Israeli regulator
- Agree INGL asset transfer agreement

Q3 2018

- Complete detailed design for topsides and hull
- Issue report on major hazards
- Expected approval of Karish Lease Environmental Document

Q4 2018

- TechnipFMC to commence fabrication of FPSO hull and topsides

Outlook

Energean is currently the only upstream Company on the LSE with considerable exposure to the Eastern Mediterranean, an area which is attracting increasing interest from global oil and gas majors. As a fast-moving independent, our aim is to take advantage of this trend and be part of the substantial infrastructure developments that will connect the region to local and wider markets.

As we progress through 2018, we are confident that our ability to acquire, de-risk and develop projects of significant scale can deliver a flow of new opportunities in the region.

We are well placed to capitalise on our growth plans and have the infrastructure, local relationships and track record to move swiftly on future value-accretive opportunities for all our stakeholders.

Mathios Rigas
Chief Executive Officer

Unlocking our value potential in the Eastern Mediterranean

Our business model explains how we create value over the short, medium and long term. We believe the following factors combine to deliver a compelling investment proposition.

What we do



Produce

We seek to maximise near-term value from our low-cost base to generate sustainable long-term cash flows.

Near-term value generation



Develop

We are implementing active development programmes in Israel and Greece. Our most significant underdeveloped assets are the Karish and Tanin offshore gas fields located in Israel, that will materially increase the scale of the Group's operations with gas targeted for 2021.

Medium-term value generation



Explore & Appraise

We have a focused exploration strategy with several exploration prospects in Greece, Montenegro and Israel. We continually seek value-accretive opportunities in the Eastern Mediterranean.

Longer-term value generation

Our key differentiators

- Low-cost producer with stable cash flow
- Experienced and proven offshore operator
- Strategically positioned in an increasingly active region
- Track record of value creation
- Experienced management with international industry track record
- World-class partners and strong financial backing
- Strong health & safety record

Read more on pages 14 & 15

Our strategy

1. Maximising output and cash flow from our producing assets

Read more on pages 18-19

2. Developing Karish and Tanin

Read more on pages 20-21

3. Capitalising on growth opportunities in the Eastern Mediterranean

Read more on pages 22-23

4. Maintaining a disciplined financial framework

Read more on pages 24-25

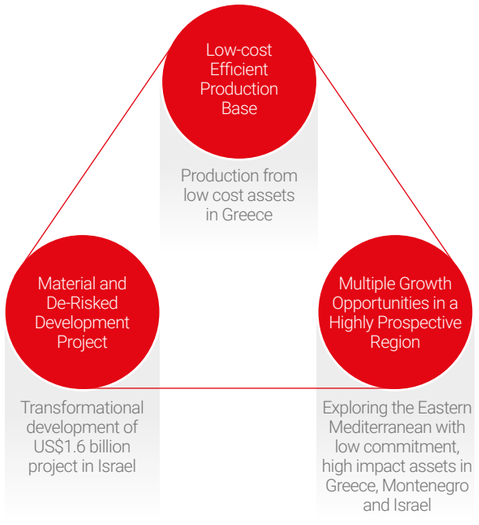
Our responsible behaviour

By successfully employing our business model we aim to create value for all our stakeholder groups, underpinned by effective risk management, sound stewardship and a culture of safety and responsibility.

Building on our key differentiators

The Energean story began in 2007. Since then, we have gone from strength to strength. Our recent Premium Listing on the Main Board of the London Stock Exchange has provided us with the platform to enhance our continuing growth and deliver our strategy of becoming the leading independent E&P in the Eastern Mediterranean.

Our strong investment proposition and key differentiators set us apart in a competitive industry. Energean's growth story is one underpinned by long-term contracts to supply oil and gas to growing markets and is backed by leading financial and industry partners.



Low-cost producer with stable cash flow

Historically, we have been able to respond to oil price volatility by reducing our cost of production per barrel (excluding depreciation) at Prinos, largely through increased production. This approach led to our cost of oil production per barrel falling from US$63/bbl in 2014 to US$25/bbl in 2017.

Our aim is to maximise production, reserves and cash flow from our existing low-cost production base, while pursuing sustainable growth and returns through active development and exploration programmes in the Eastern Mediterranean.

Experienced and proven offshore operator

Energean is the operator of the majority of its assets, including Prinos, Prinos North, South Kavala, Epsilon and Katakolo in Greece; Karish, Tanin and Blocks 12, 21, 22, 23 and 31 in Israel; and blocks 26 and 30 in Montenegro.

Our operational and technical knowledge is core to our business, including our dedicated teams of geologists, geophysicists and production and reservoir engineers, which will help us to rapidly develop projects. This extensive knowledge has been built up across the business during more than 36 years of offshore operating experience in the Prinos Basin.

This experience and in-house capability have supported the Group in maintaining stable and risk-controlled production from Prinos and provided a platform to acquire attractive assets and de-risk key development projects.

The Directors believe that operatorship affords us the flexibility to progress projects at the most advantageous rates.

We intend to maintain a flexible and prudent approach to retaining or farming out operatorship, depending on the nature of each asset and its financing structure.

Strategically positioned in an increasingly active region

Our operations are focused on the Eastern Mediterranean, with the most significant assets located in Israel and Greece, which are both OECD countries and strategically attractive for investment. By maintaining a focused approach to this region, we believe the Group has developed strong relationships with all key stakeholders.

The Eastern Mediterranean has become an increasingly active area for E&P. Recent discoveries of material gas fields in Egypt and Israel (the Zohr and Leviathan fields, respectively) have drawn attention and investment to the region. In Greece, Exxon Mobil, Total, Edison and Repsol have been attracted to the hydrocarbon sector and have acquired, or expressed an interest in acquiring, Greek exploration blocks.

As an independent, locally-based E&P company, Energean is well positioned to move swiftly on opportunities in the Eastern Mediterranean.

Track record of value creation

Energean has a strong track record of value creation through timely acquisitions and efficient development.

The Prinos Basin licence was acquired in 2007, at what the Directors believe was a relatively advantageous valuation level. We have since been able to secure a licence extension and have increased reserves through technical reappraisal of the reservoir and drilling activity, enabling the implementation of a low-cost development plan.

The most recent Netherland, Sewell & Associates, Inc. Competent Person's Report ('NSAI CPR') for Prinos estimates that Prinos Basin 2P assets will have a cumulative net cash flow (discounted at 10%) of approximately US$0.7 billion through 2035.

The value of Prinos to the Group is further enhanced by a four-year extension of Energean's long-term offtake agreement with BP, from 2021 to 2025, for 100% of Prinos production. BP has been the Group's offtaker in the Prinos Basin since 2013.

The Karish and Tanin leases were acquired in 2016 for US$148.5 million. The assets were sold due to a regulatory requirement relating to the seller.

The acquisition of Karish and Tanin was completed at a lower US$/boe value than other discoveries in the region, at a US$/boe value of 0.4 (excluding royalties), while Zohr (Egypt) and Aphrodite (Cyprus) have US$/boe values of 1.4 and 0.8, respectively (source: IHS Energy database – Herold).

At the time Energean acquired them, Karish and Tanin were stranded assets with no gas contracts in place. Since the acquisition of these leases, the Group has achieved a number of key milestones, including the approval of the Karish and Tanin Field Development Plan ('FDP') in August 2017. We have also signed 12 Gas Supply Agreements, totalling an estimated 4.2 BCM per annum on an annual contract quantity ('ACQ') basis, or 3.1 BCM per annum on a take or pay basis.

Currently discovered 2C from Karish and Tanin equate to an estimated NPV of US$830 million net to Energean (70% ('WI')). This uplift in value has been realised in the space of 15 months, due to Energean's ability to execute key project milestones quickly and effectively.

In addition, Energean has secured a number of attractive exploration licences in Israel, Western Greece and Montenegro, where we believe we can add value.

As our track record demonstrates, Energean continually assesses ways to create further sustainable value and act upon value-accretive opportunities.

Experienced management with international industry track record

Energean's management team and staff are drawn from international and national oil companies, major and smaller independents and engineering contractors.

Management's experience encompasses a broad range of projects, asset types – including offshore (shallow and deep water) assets – and E&P technology, with over 200 years' combined experience in the oil and gas industry.

We have offices in the UK, Israel, Greece, Cyprus, Egypt and Montenegro and our technical team has recently been expanded to support the move into deep water operations at Karish and Tanin.

World-class partners and strong financial backing

The growth and success of our business has been supported by our strong partnerships with industry-leading technical experts and the financial backing of major banks and specialist investors.

These world-class partners, in addition to our strong customer relationships, have enabled us to realise our potential and will be integral to our future as we transform Energean into a leading international oil and gas business.

Strong health & safety record

Energean's exemplary HSE performance is a key aspect of our overall success. We have operated in the Kavala and Thassos Island areas in Greece, both of which are environmentally sensitive locations with high tourist activity, for over 37 years.

Energean Gas benefitted from this experience and we believe that the Gulf of Kavala's continued biodiversity and popularity with tourists are testament to our ability to conduct our operations in an environmentally sound and responsible manner.

Our HSE record has been an important factor in our success in bidding for licences and we are committed to maintaining the health and safety of all our employees and other stakeholders.

Maximising opportunities in a highly prospective region

The Eastern Mediterranean

The Eastern Mediterranean is an increasingly active E&P region. Recent discoveries in Egypt and Israel (the Zohr and Leviathan gas fields, respectively), as well as the Aphrodite and Calypso fields in Cyprus, have drawn investment from global oil and gas majors.

The region represents a large captive market in which governments are seeking to transition to cleaner sources of energy and are keen to expand sovereign resources. Growing demand from Western Europe for alternative sources of gas has raised the prospect of strategic pipelines being put in place that will considerably increase the economic importance of Eastern Mediterranean assets.

Our opportunity

Energean is well positioned to target and compete for opportunities in this region. In addition to our strong track record of value creation from assets in the Prinos Basin, we have secured world class industry partners (such as BP, Repsol and Prime Marine) and strong financial backing from the European Bank for Reconstruction and Development (EBRD), Kerogen Capital and Third Point.

Our expanding presence in the Eastern Mediterranean will strengthen our ability to create new opportunities.

Game-changing gas discoveries

The Eastern Mediterranean has seen a number of major gas discoveries in the last decade. These include the Tamar gas field, currently estimated to contain 11.2 Tcf of gas reserves, in 2009 and the Leviathan gas field, estimated to contain 21.4 Tcf of gas, in 2010, both off the coast of Israel.

Cyprus' oil and gas sector has experienced significant expansion following the discovery of the Aphrodite gas field, with an estimated 4 Tcf of natural gas, in January 2012. ENI, Total, Exxon Mobil and Qatar Petroleum are currently operating in the country.

In February 2018, ENI announced the Calypso 1 gas discovery, offshore Cyprus, which it described as 'a promising gas discovery that could contain more than 230 BCM of gas'.

Increasing M&A activity

The Eastern Mediterranean has recently received investment from world class companies.

Landmark deals in the region include Tamar Petroleum's purchase of a 7.5% stake in the Tamar natural gas reserve in January 2018, for US$560 million and 38.5 million shares. Two Zohr field deals were concluded in Q4 2016, with Rosneft acquiring a 30% share in the field for US$1.125 billion and BP securing a 10% interest in the Shorouk concession, offshore Egypt, which contains the Zohr gas field, for US$375 million. In March this year, UAE's Mubadala Petroleum acquired a 10% stake in Shorouk for US$934 million. In February 2018, two Israeli firms signed a US$15 billion agreement to export gas to Egypt from Leviathan and Tamar. The deal will see 64 BCM of gas supplied over 10 years with an implied price of c.US$6.6/mmbtu.

East Med Pipeline and export routes to Europe

A 1,700km pipeline connecting the Eastern Mediterranean's Levantine Basin (Israel) with the European gas network, via Greece and Italy, is due for completion in 2025.

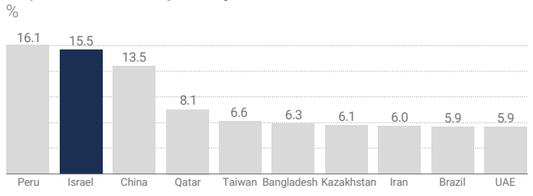
Known as the East Med Pipeline, this development has been classified as a European Project of Common Interest. A MoU has already been signed between Israel, Greece, Italy and Cyprus to support the expected US$6–7 billion pipeline construction.

Regional market overview

Israel

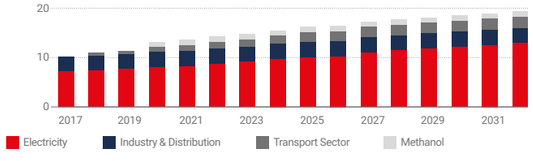
Over the last decade, Israeli natural gas demand has been among the fastest growing globally. Future demand is forecast to increase substantially, primarily driven by the electricity sector to serve population growth, rising living standards, increased water desalination, electrification of the railway system, and the adoption of electric vehicles and compressed natural gas ('CNG') for transportation. Israel consumed 10.4 BCM of gas in 2017. The Israeli Ministry of Energy anticipates that demand will increase to 12.5 BCM in 2020 and to 18 BCM by 2030, of which 85% will be for electricity generation and industrial use.

Gas demand increase 2006–2016 CAGR
Top 10 countries globally

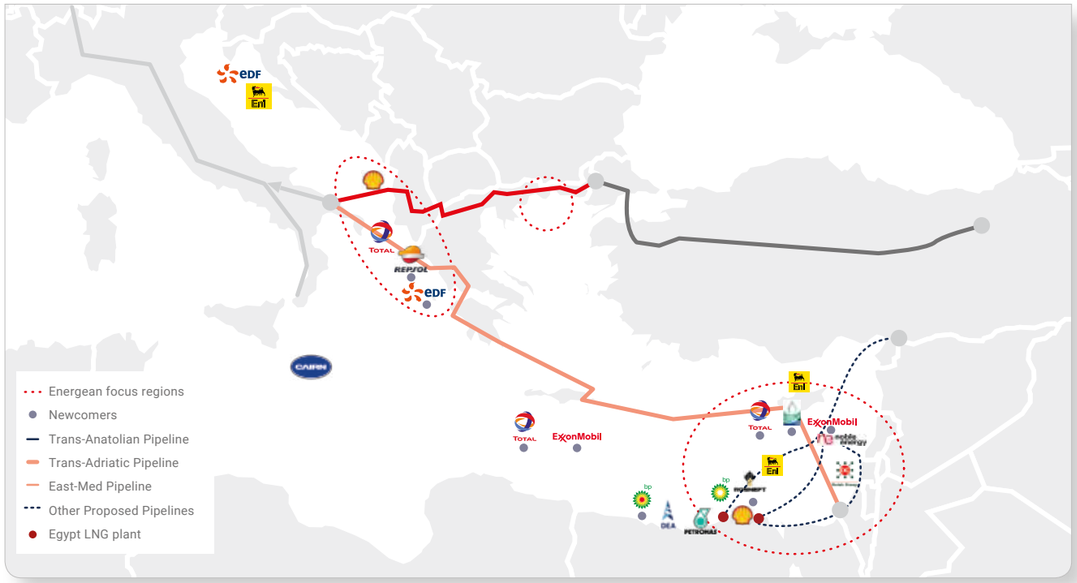


In a move to break up the Noble and Delek monopoly and foster competition, the Israeli government introduced various legislative measures, such as the Natural Gas Framework ('NGF'), which enabled Energean to acquire the Karish and Tanin fields.

Israeli natural gas demand by sector



Source: Israeli Electric Corporation; Israeli Ministry of Energy; BP Statistical Review of World Energy June 2017



Greece

Energean is currently the only company in Greece operating producing oil and gas assets.

Interest in the country from international oil and gas companies is growing. A consortium of Exxon Mobil, Total and Hellenic Petroleum has bid for two licences offshore Crete, and Repsol and Hellenic have jointly bid for a block in the Ionian Sea.

Energean also operates four development stage fields at Prinos and Prinos North in Kavala, Epsilon in Northern Greece and Katakolo in Western Greece.

Montenegro

The Eastern Adriatic remains underexplored, despite having what appear to be all the necessary hydrocarbon-generating components. Large prospects have been identified offshore Montenegro. These are on a par with recent oil discoveries in northern Albania, such as the onshore Shpirag-2 discovery. To date, over 5 billion barrels of oil in place have been discovered within this prolific carbonate play.

In March 2017, Energean signed a concession agreement with Montenegro for offshore Blocks 30 and 26. The NSAI Ioannina and Montenegro CPR indicates that the two blocks hold best estimate unrisked prospective resources of 1.8 Tcf of natural gas and 143.9 MMbbls of liquids.

Future pipeline developments

There are currently three major pipeline projects which could traverse Greece. The Trans-Anatolian pipeline is planned to run from the Turkish border with Georgia, to the Greek border at Edirne. Here, the pipeline will connect to the Trans-Adriatic pipeline, which is planned to run across Greece to Albania in the west. The East Med pipeline is planned to run from the Levantine basin (Israel) to Cyprus then to Crete, the Peloponnese and finally connect with the Poseidon pipeline to Italy.

A floating gas storage and regasification unit offshore Alexandroupolis is expected to begin operations in 2020, creating a fourth import route to Greece.

Oil price outlook

Oil prices began to recover in 2017 following the oil price crash in mid-2014. However, prices remained volatile, ranging from US$44.82/bbl (21 June 2017) to US$67.02/bbl (26 December 2017).

Energean's conservative financial management and its focus on operating costs give the Group confidence that it can prosper under a range of oil prices.

Maximising output and cash flow from our producing assets

Energean is focused on a clear strategy of producing, developing and exploring existing and new assets in the Eastern Mediterranean. By maximising the potential of our assets and building momentum in this increasingly active region, we aim to deliver real value in this new era of our growth story.

Our focus for the next 12 months

- Complete Prinos Alpha in-fill programme (PA-32 drill, PA41 w/o, PA-33 maint)
- Deepen PA-32 to Kazaviti and undertake production test
- Add to the Alpha programme an ERD well drilled to Epsilon
- Commence fabrication of Lamda jacket for the Epsilon field

Maximising our low-cost production base

A key strategic priority is to increase Prinos Basin production and cash flow. Our existing development plan targets the monetisation of 2P reserves of 39.5 MMbbls of oil and 6.0 Bcf of gas, as well as 2C resources of 22.9 MMbbls of oil and 5.3 Bcf of gas, as of 31 October 2017, according to the NSAI Prinos CPR. Our long-term development plan from 2018–2021 includes: drilling 24 new wells; constructing an unmanned platform to exploit the Epsilon Field, adjacent to Prinos; and infill drilling in the existing producing fields. We estimate average 2P production rates to increase to 4,000–4,500 bopd in 2018 as new infill wells are brought on stream in the Prinos complex.

Developing Karish and Tanin

The development of the Karish and Tanin 2.4 Tcf gas project, offshore Israel, will ultimately transform the Group's business and position us as a significant player within the Eastern Mediterranean.

Our focus for the next 12 months

- Complete detailed design (Subsea and FPSO)
- First steel cut – FPSO hull and topsides
- Commence construction of pipeline beach crossing
- Mobilise Stena Forth drill ship and spud first well

Working in partnership with world-class contractors

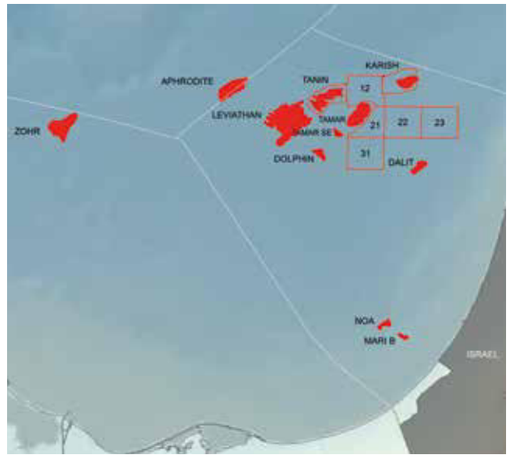
TechnipFMC
EPCIC contract for FPSO

Stena Drilling
Contracted for 3 firm and 5 optional wells

Wood Group
Pipeline operations service contract

Halliburton
Drilling services

A transformational project in Israel



World-class asset

2.4 Tcf
2C resources

World-class exploration potential

2.5 Tcf
Unrisked prospective resources

Gas sales

4.2 BCM per year
Gas contracts in place

Substantially de-risked project

FID
Achieved March 2018

Delivering commercial production from Karish and Tanin will ultimately transform our business. With an estimated 2.4 Tcf of natural gas and 32.8 MMbbls of liquids (2C resources) and 2.4 Tcf of natural gas and 70.9 MMbbls of liquids (prospective resources), these assets are highly strategic for the development of the Israeli energy market and can help to meet increasing Israeli demand, increase market competition and improve security of supply.

The Karish and Tanin development will position Energean as a significant player within the region. The FDP for Phase 1 of the project was approved by the Israeli government on 27 August 2017, with the final investment decision taken in the first quarter of 2018 and first gas expected in the first half of 2021.

Key milestones to Karish and Tanin first gas

2018

March 2018
FID

Q4 2018
FPSO First steel cut

2019

Q1 2019
Commence sales gas pipeline beach crossing at Dor

Q1 2019
Mobilise Stena Forth rig

Q3 2019
Install sales gas pipeline from Dor to Karish field

Q4 2019
Complete evaluation of shallow and deep potential in Karish Main field

Q4 2019
FPSO hull sails from China to Singapore

2020

Q1 2020
Karish main development wells cleaned up and suspended

Q2 2020
Installation of production manifold and other sub-surf structures

Q4 2020
Sailaway of completed FPSO

2021

H1 2021
First gas production

Capitalising on growth opportunities in the Eastern Mediterranean

Energean is well positioned, as an independent operator in an increasingly active region, to advance existing and future development and exploration prospects.

Upside potential

Energean has a number of development and exploration opportunities within our current portfolio, including, but not limited to further Prinos Basin development and exploration potential; development and exploration blocks in Western Greece, Katakolo, Aitoloakarnania and Ioannina; blocks 26 and 30 offshore Montenegro; and various inorganic growth opportunities aligned with our strategy. These include five blocks for which Energean Israel was awarded licences in Israel's First Offshore Bid Round, which concluded on 15 November 2017.

One example of the inorganic growth opportunities available to the Group is the oil and gas industry in Cyprus, which has experienced significant growth following the discovery of the Aphrodite gas field, with an estimated 4 Tcf of natural gas, in January 2012. ENI, Total, Exxon Mobil and Qatar Petroleum are currently operating in the country, with Total and ENI having commenced drilling in Cyprus in July 2017. In February 2018, ENI announced the Calypso 1 gas discovery, offshore Cyprus. Accordingly, Cyprus represents a further opportunity to expand our operations within the Eastern Mediterranean.

Greece

Exploration upside in Western Greece (Aitoloakarnania, Ioannina and Katakolo)

Additional reserves at Katakolo

Montenegro

Blocks 26 and 30 awarded to Energean in March 2017

Israel

The Israeli Petroleum Council awarded Energean 5 new licences (for Blocks 12, 21, 22, 23 and 31) in December 2017

Our focus for the next 12 months

- Plan two low-risk exploration wells to bracket the Karish-Main development drilling campaign.
- Drill two wells to identify Epsilon upside potential in discovered and deeper horizons
- Shoot 3D seismic surveys in Israel and Montenegro
- Shoot 2D seismic survey in Western Greece (Repsol operator)
- Secure operatorship of an additional development project
- Gather data to underpin plans for Prinos EOR (tertiary) development
- Take FID on Katakolo or farm down
- Expand Greek portfolio of low-cost, near-field, exploration prospects

Maintaining a disciplined financial framework

We have successfully built a conservative balance sheet by careful working capital management and maintaining low levels of bank debt throughout the commodity down-cycle and periods of subdued oil prices.

Leveraging financial flexibility

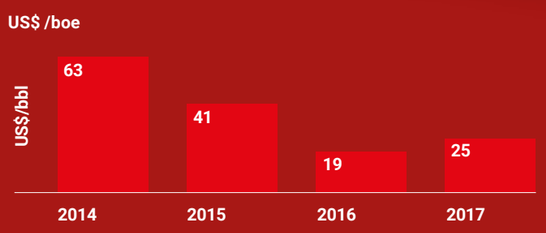
A key strategic priority is to maintain balance sheet flexibility going forward, with leverage minimised at the corporate level by managing contractor payables alongside disciplined capital deployment.

We will seek to maintain strict investment criteria for new projects, typically targeting an unlevered internal rate of return of more than 15%. We are confident that this approach, alongside our production, development and exploration opportunities, will underpin our sustainable growth in the future.

Our focus for the next 12 months

- Delivering Karish and Epsilon development programme in line with capital expenditure budget
- Optimise the use of capital by ensuring the highest possible return
- Maintain liquidity to enable the Company to capture exploration or business development opportunities as they may arise
- Grow production to maximise cash from operating activities

Focus on cost control over production



How we measure our success

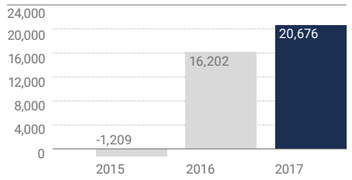
We measure our performance over a range of financial, operational and non-financial metrics to ensure we are managing our long-term success in a sustainable way and in line with our strategic objectives.

Financial

Adjusted EBITDAX
(US$ 000)

20,676

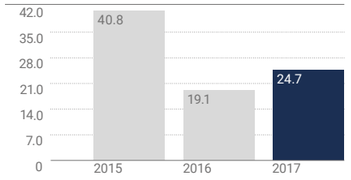
2016: 16,202



Cost of oil production per boe
(US$)

24.7

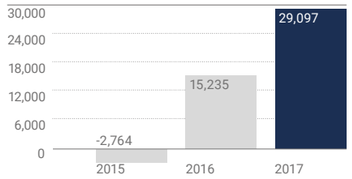
2016: 19.1



Cash flow from operating activities
(US$ 000)

29,097

2016: 15,235

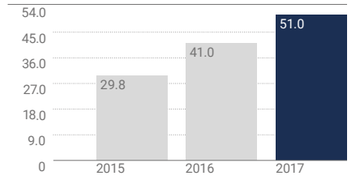


Operational

2P reserves
(mboe)

51.0

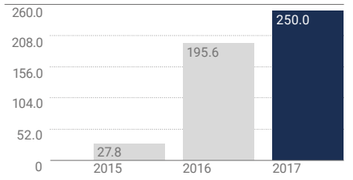
2016: 41.0



2C resources
(mboe)

250.0

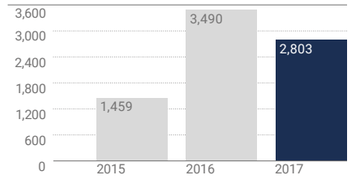
2016: 195.6



Average production per day
(bopd)

2,803

2016: 3,490

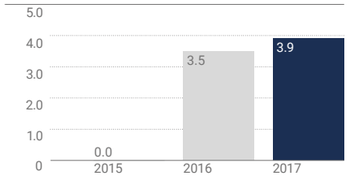


HSE

Lost time injury frequency rate
(Average number per million hours worked)

3.9

2016: 3.5



Building a balanced portfolio

2017 was a significant year in Energean's development. Our focus was on establishing a foundation for further growth across all stages of the upstream life cycle.



Operational achievements in 2017

- Preparation and approval by the Israeli Government Authorities of a Field Development Plan ('FDP') for our first deep water gas developments – Karish and Tanin
- Completion of financing arrangements for the Epsilon Field Development project in Greece
- Drilled 3 new side tracks and undertook 2 workovers increasing production from 2650 bbls/day in January to 3758 bbls/day in December
- Establishment of an office in Montenegro and the commencement of planning for seismic evaluation of our two highly promising exploration Blocks 26 and 30, awarded to Energean in March 2017
- Undertaking environmental studies ready for submission of an Environmental Impact Assessment to the Montenegrin government, as well as a 3D survey design
- Participated in 1st Israeli Offshore Exploration License round. Awarded blocks 12, 21, 22, 23 and 31 in December

Prinos operations

The first half of the year was operationally challenging for our producing Prinos Basin assets. Problems related to asphalt precipitation prevented us from maintaining the production growth we achieved in 2016.

As a consequence of these measures, average yearly production fell to 2,803 bopd in 2017, from 3,490 bopd in 2016. This contributed to an increase in our cost of production to US$24.7/boe from US$19.1/boe year on year. Following modifications to the well completion design and refinement of certain operational practices, these issues were largely eradicated and production growth restarted. We finished 2017 with production in Q4 averaging 3,405 bopd.

Production, maintenance and marine operations at Prinos were executed successfully during 2017. No significant incidents occurred. A bi-annual shutdown campaign was completed with the main underwater pipelines successfully pigged.

To prevent future asphaltene issues, single string completion designs have been adjusted to allow deeper injection of inhibitor, improved asphalt prediction curves have been developed based on samples from the new wells and drawdown rates are being better managed to maintain bottom hole pressure above asphalt onset point.

We expect to achieve average production rate of between 4,000-4,500 bopd from Prinos for 2018, an increase of 40-60% compared to 2017. During 2018, a further five development infill wells are planned to be drilled.

All of the Group's production from the Prinos Basin assets in 2017 was sold through a long-term offtake agreement with BP, under which BP typically collects on a quarterly basis. Energean's average realised sales price for 2017 was US$46.73/bbl. This offtake agreement was recently extended to November 2025, eliminating our offtake risk for the foreseeable future as we scale up production in the Basin.





Following the successful appraisal well drilled into the Kazaviti structure in 2016 (deepening of development well PA-36) contingent resources were recognised and a development well is being planned for inclusion in the ongoing Prinos infill drilling campaign.

Work on the Katakolo project in the Greek Peloponnese focused on execution of the necessary environmental studies required to obtain approval for the construction of the initial two wells and associated pilot production facilities. Further sub-surface studies were completed, allowing 10 MMbbls of proved and probable reserves to be recognised.

Resources were also recognised on the 1990s Delta discovery that sits below the partly developed Prinos North satellite. A proposal for an extended reach well from the Prinos platform has been prepared.

In Western Greece, Energean successfully farmed out 60% of our interest and operatorship for our Ioannina and Aitoloakarnania Blocks, onshore Western Greece, to Repsol in September 2017, who will carry 90% of the gross exploration costs, up to US$49.9 million.

Montenegro

In March 2017, Energean signed a concession contract to explore blocks 26 and 30, offshore Montenegro, which hold best estimate unrisked resources of 1.8 Tcf natural gas and 143.9 MMbbls of liquids.[1]

We established an office in Montenegro and commenced work to allow a 3D seismic survey to be performed in 2018. Environmental baseline studies have been completed and an Environmental Impact Assessment is in preparation.

Egypt

In 2017, the Group drilled just one exploration well – in the West Kom Ombo licence in Egypt. This proved to be a dry hole and the licence was subsequently relinquished.

1 Based on NSAI Ionnina and Montenegro CPR, October 2017

Karish and Tanin

In Israel, we made major steps forward in the development of the Karish and Tanin gas fields, acquired from Delek Energy in 2016. Engineering work commenced in January 2017 and ran through the entire year. Feasibility work completed during 2016 demonstrated the attractiveness of developing the project through an FPSO located at the Karish field. This approach removes the need to land hydrocarbon liquids in Israel, minimising environmental impacts, and will establish a hub through which other discoveries could be developed.

To fast-track the development of Karish to produce first gas in 2021, Energean contracted TechnipFMC to design, procure, construct, install and commission all facilities from the wellhead to the entry point of the Israeli gas grid. This approach minimises interfaces and hence execution risk for the Group.

An FDP for Karish and Tanin was submitted in June 2017 and approved by the Israeli authorities in August. FEED work was undertaken between June and December.

In parallel with preparing the FDP, we secured gas supply contracts for around 4.2 BCM per year for 16 years to Israeli gas buyers. Options for a further 12 BCM were also agreed.

Detailed design work for the Karish and Tanin development commenced towards the end of 2017 and will continue throughout 2018, with first steel cuts on the hull and topsides expected towards the end of this year.

In January 2018, Energean announced it had selected Stena Drilling as its preferred drilling contractor, following a competitive tendering process. Three development wells will be drilled at Karish in 2019. Drilling services will be provided by Halliburton and well engineering by Lloyds Register.

A contract to cover all operations readiness and assurance work was tendered and awarded to Wood Group in March 2017.

In addition, we have been gradually extending our team in Israel and recruiting local staff to deliver the in-country scope and to manage all local interfaces and stakeholders.

Exploration, appraisal and development activities

Exploration represents an important element in the Company's growth portfolio. The main focus in 2017 was on extending and upgrading our exploration portfolio in Israel and Greece, in preparation for further drilling when cash flow from increased Greek production will be available.

Israel

The Israeli government announced and executed the country's First Israeli Offshore Bid Round in 2017. Energean decided to bid only on blocks within a 40km radius of the Karish field, namely Blocks 12, 21, 22, 23 and 31. Following the conclusion of the Bid Round in November, Energean was awarded licences for all five blocks in December. No firm well commitments were required.

In parallel with winning these new blocks, work also continued on maturing the significant exploration prospects mapped in the Karish lease. Well proposals for Karish North and Karish East were prepared and options secured in the drilling contract with Stena to allow them to be added onto the Karish Main Development drilling sequence.

Greece

In Greece, work continued throughout the year on the infill development campaign of our main producing field: Prinos. Three new wells were completed – PA-33, PA-37 and PA-38 – and wells PA-40 and PA-19 were worked over. Well PN-H4 – the first extended reach well to be drilled by our own rig – was drilled towards the end of 2017. Development drilling activities were generally successful, with unswept oil being found as targeted. Reserves developed per well were in line with expectations.

Meanwhile, work continued on the development of the Epsilon satellite. This requires the installation of a new drilling platform plus three 3.5km long pipelines connecting it to Prinos. The design was adjusted to allow the contractor, GSP, to build the jacket, topsides and pipelines, while also drilling three early appraisal/development wells. Finance for this work was secured with the Black Sea Development Bank and Romanian Export Import Bank. Costs were in line with the earlier development concept.

Work addressing the potential installation of a new platform at the Prinos complex was also progressed. Options to extend the existing B platform were generated and will be compared with a new bridge-linked jacket. This new facility will be required after the drilling of Epsilon development wells is completed.

Building the financial framework for growth



Panos Benos
Chief Financial Officer

We remain focused on capital discipline, cost control and efficiency.

2017 found Energean with a major task of converting its newly acquired Karish & Tanin gas discoveries, offshore Israel, into a commercial project. In order to achieve Final Investment Decision Energean met the following key milestones:

- finalisation of Field Development Plan that was submitted to and approved by the Israeli authorities
- execution of 12 long term gas sales agreements totalling an estimated 61 BCM on an ACQ basis (up to 74 BCM including OR gas supply agreement) with reputable and credible counterparties
- agreement of financing terms for a US$1.275m Project Finance with major international banks.

In Greece, oil production from the Prinos licence was materially impacted by the scheduled turnaround of the Prinos facilities in September 2017, with production being shut for 18 days, and the well performance issues experienced in the first half of the year which resulted in an unplanned recompletion programme of a number of producers and the delay of the infill drilling schedule. Post September both the production from existing wells and the drilling operations resumed with PA 37 and PNH4 wells coming on-stream in December 2017 and March 2018 respectively.

Furthermore, the Group progressed with the Epsilon development plan delivering the following:

- Signing of a US$88.3 million turnkey EPCIC contract with GSP Offshore S.R.L. which includes the drilling of the first three development wells, the construction and installation of an unmanned satellite platform to the main Prinos complex and procurement and installation of the pipelines and umbilical to connect the new Lamda platform to the Prinos Delta platform
- Agreeing terms for the upsizing of the Reserve Based Lending facility with the EBRD from US$75million to US$180 million with the participation of other lenders including the Black Sea Trade and Development Bank, Banca Comerciala Intesa Sanpaolo Romania S.A. and the Export-Import Bank of Romania Eximbank SA. The tenor of the loan was extended to 2024 with first repayment in Q2 2020.

The Group continued its prudent and cautious exploration expenditure and commitment strategy, underpinned by key commercial agreements and strategic decisions:

- Farm-out of a 60% interest in the Ioannina and Aitolokarnania licences to Repsol for a consideration of US$1.0 million in cash and a carry of 90% of the first exploration phase costs, up to a pre-agreed maximum of US$49.9 million.
- Signed an exploration and production concession contract with the State of Montenegro covering offshore blocks 4219-26 and 4218-30 for work commitment amount €3.0 million
- Awarded five exploration licences for blocks 12, 21, 22, 23 and 31 offshore Israel, near to the existing Karish and Tanin fields
- Received approval for the Field Development Plan of the Katakolo field in Western Greece from Hellenic Hydrocarbons Resources Management
- Relinquishment of West Kom Ombo licence in Egypt and recognition of impairment of US$9.3 million.

Energean funded its operations and activities in 2017 by a combination of:

- Operating Cash Flow of US$29.1 million generated from the Prinos and Prinos North fields
- Kerogen Capital committed funds of US$20 million for the Karish Tanin pre-FID work
- Available funds of US$33 million from the EBRD committed facilities to fund our operations in Greece.

In spite of the Group's expansion and growth during the year, we remained focused on capital discipline, cost control and efficiency by:

- Total third party Net Debt of US$75.6 million (2016: US$48.5 million) resulting in a very low Gearing ratio of 26.17% (2016: 24.39%). The increase in Net Debt is driven by the drawdown of available funds under the RBL Facility, but the Gearing ratio has remained well below 30%
- Production cost of US$25.3 million (2016: US$24.3 million). and production cost per barrel for the year of US$24.7 (2016: US$19.1). The production cost in 2017 when adjusted for the $0.8m scheduled shutdown has remained steady. The production cost per barrel has been affected by the lower production delivered through the year but is still at very competitive levels
- Total Group G&A of US$6.0 million (2016: US$4.1 million), The G&A increase, reflects the additional staffing and administrative costs caused by the rapid growth of the Group's portfolio with the acquisition of Karish and Tanin and the efforts to bring the asset to Final Investment Decision in early 2018.

The above, coupled with the improved oil price environment during 2017 with a realised sales price of $46.7/barrel (2016: US$34.3) resulted in significantly improved financial performance as reflected below:

Financial results summary

	For the year ended 31 December		
	2017	2016	Change
Adjusted EBITDAX (US$ 000)[1]	**20,676**	16,202	28%
Net cash from operating activities (US$ 000)	**29,097**	15,235	91%
Cash capex (US$ 000)[1]	**54,003**	110,680	-51%
Capital expenditure (000 US$)[1]	**67,635**	104,764	-35%
Total production for the period (boe)[3]	**1,023,072**	1,273,751	-20%
Average production per day (bopd)[3]	**2,803**	3,490	-20%
Sales volume (boe)	**1,179,368**	1,133,987	4%
2P reserves (mboe)[2]	**51**	41	24%
2C resources (mboe)[2]	**250**	196	28%
Cost of oil production (US$ 000)[1]	**25,262**	24,303	4%
Cost of oil production per boe (US$)[1]	**24.7**	19.1	29%
Gross profit (US$ 000)	**9,104**	(827)	1201%
Operating loss (US$ 000)	**(13,696)**	(10,870)	26%
Income/(loss) before tax (US$ 000)	**25,407**	(49,897)	151%
Net debt (US$ 000)[1]	**75,639**	48,458	56%
Gearing ratio (net debt/capital)[1]	**26.17%**	24.39%	7%
Realised sales price (US$)	**46.7**	34.3	36%

[1] Underlying Adjusted EBITDAX, cost of oil production per boe, capital expenditure, cash capex, net debt and gearing are non-IFRS measures and are explained later in this section.
[2] 2P reserves and 2C resources figures as per NSAI CPR 31 October 2017 and include gas and liquids volumes with gas volumes converted from Bcf at the rate of 5.8. Includes 50% of volumes set out in the Karish and Tanin CPR, of total 449 mboe. Energean Israel Limited's working interest was 50% as of the year ended 31 December 2017 and rose to 70% in March 2018 reflecting an increase in 2C resources to 340 mboe.
[3] Production levels refer to total oil production for the periods. Oil volumes are STOB and include natural gas liquids. Average production per day for the year ending 31 December 2017 would be 2,948 bopd if excluding 18 days of scheduled maintenance during which the plant was shut down.

Revenue

The Group's revenue increased by 45.4% to US$57.8 million for the reporting period (2016: US$39.7 million). This is mainly explained by the increase in the average realised crude oil price from US$34.25/bbl during 2016 to US$46.73/bbl during the reporting period.

Cost of oil production, depreciation and impairments

Cost of oil production amounted to US$25.3 million; US$24.7/boe (2016: U$24.3 million; US$19.1/boe). Cost of production in 2017 includes an amount of US$0.8 million for turnaround expenditures.

Depreciation charges in cost of oil production decreased by 16.9% primarily as a result of an increase in 2P reserves.

During 2017, the Group relinquished West Kom Ombo licence in Egypt and wrote off US$8.0 million in relation to exploration expenditure and US$1.3 million for the licence's letter of guarantee.

Exploration costs written off

	2017 (US$ 000)	2016 (US$ 000)
Exploration costs written off	8,007	–
Provision for bank guarantee	1,285	–
Total cost related to West Kom Ombo licence written off	**9,292**	**–**

Gain on derivative

The gain on derivative of US$25.8 million is a result of the valuation of a derivative financial instrument, measured at fair value at the end of each reporting date, which related to the Energean Israel Limited Class B Shares the Group had a contingent commitment to acquire. Pursuant to the Reorganisation Agreement, the Group had committed to acquire in an exit event 50% of the Energean Israel Limited Class B Shares of Energean Israel Limited held by the Founders. The valuation technique used to value this asset multiplies the estimated likelihood of an exit (being an IPO or a sale) by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares to be acquired under the commitment. Pursuant to the Reorganisation Agreement, the Group acquired the Founders' 50% economic interest in Energean Israel on 16 March 2018 in exchange for US$10 million, leaving the Group with a 50% economic interest and 50.0001% voting rights in Energean Israel. Pursuant to Second Subscription Agreement with Kerogen and after taking a final investment decision in respect of the Karish and Tanin assets the Group's interest in Energean Israel was further increased to 70% on 29 March 2018.

Financing costs

Financing costs for the year were US$22.9 million (2016: US$ 29.3). The decrease in financing costs is associated with shareholders loan conversion to preference shares at the end of H1 2017.

Taxation

Taxation expense was US$14.1 million in the year (2016: income of US$11.5 million). The higher taxation expense is mainly due to higher deferred tax credits in unrealised foreign exchange differences in the Greek entities and due to recognition of income tax liabilities in relation to the Kavala Oil tax appeal.

Income after tax from continuing activities and profit per share

Income for the year from continuing activities amounted to US$9,943 million (2016: loss of US$38.6 million). Profit per share was 14 cents (2016: loss of 0.54 cents).

Cash from operating activities

Net cash flows from operating activities increased to US$29.1 million for the reporting period (2016: US$15.2 million) and was primarily attributable to an increase in the realised oil price and decrease in inventory balance. This cash flow together with increased debt facilities funded the Group's US$54 million capital expenditure on exploration and development.

Capital expenditures

2017 capital expenditures amounted to US$67.6 million (2016: US$104.8 million) with US$64.4 million invested in development activities and US$3.2 million in exploration and appraisal activities. More than 90% of the total capital expenditure was invested in Greece, with three new wells completed – PA-33, PA-37 and PA-38 – and wells PA-40 and PA-19 were worked over. Well PN-H4 – the first extended reach well to be drilled by our own rig – was being drilled at year end.

Liquidity risk management and going concern

The Group closely monitors and manages its liquidity risk. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices and different production rates from the Group's producing assets.

The Directors have assessed the current financial position and the profitability of the Group as well their expectations in relation to future business prospects, and future profitability and cash flows of the Group.

The Group's forecasts show that the Group will be able to operate within its current debt facilities and have sufficient financial headroom for the following 12 months. Another important factor for determining that the going concern basis remains appropriate is the ability of raising necessary funding as and when needed. Subsequent to the balance sheet date, the Group having successfully completed an IPO on the London Stock Exchange raised $460 million gross proceed. Furthermore the Group's liquidity position has been significantly improved by the amendment of the Group's existing EBRD Senior Facility agreement signed on 30 January 2018, increasing the facility size to US$180 million from US$75 million and the addition of a US$1.275 billion Senior Credit Facility agreement, which will be used to fund the Karish and Tanin development costs.

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures include adjusted EBITDAX, cost of oil production capital expenditure, cash capex, net debt and gearing ratio are explained overleaf.

Adjusted EBITDAX

Adjusted EBITDAX is calculated by the Group as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange gain / (loss) and exploration and evaluation expenses. The Group presents adjusted EBITDAX as it is used in assessing the Group's growth and operational efficiencies as it illustrates the underlying performance of the Group's business by excluding items considered by management not to be reflective of the underlying operations of the Group.

	2017 (US$ 000)	2016 (US$ 000)
Adjusted EBITDAX	**20,676**	16,058
Reconciliation to profit before tax:		
Depreciation and amortisation expenses	**(18,008)**	(21,355)
Exploration and evaluation expenses	**(9,966)**	(1,133)
Other expenses	**(8,187)**	(4,688)
Other income	**1,789**	248
Finance income	**14**	327
Finance costs	**(22,940)**	(29,311)
Gain on derivative	**25,786**	–
Net foreign exchange (loss)/gain	**36,243**	(10,043)
Profit/(loss) from continuing operations before tax	**25,407**	**(49,897)**

Cost of oil production

Cost of oil production is defined as cost of oil sales, less cost of services, depreciation and change in inventory (defined as the difference between opening inventory and closing inventory). Cost of oil production per boe represents cost of oil production divided by total production for the respective period.

Cost of oil production is a useful indicator of the Group's underlying cash costs incurred to produce oil and gas. Cost of oil production eliminates certain non-cash accounting adjustments to the Group's cost of sales to produce oil and gas. The Group uses these measurements to compare the performance of the Group's operations period-to-period, to monitor costs and to evaluate operating efficiency.

	2017 (US$ 000)	2016 (US$ 000)
Cost of oil sales	**47,905**	40,551
Less		
Depreciation	**(17,640)**	(21,218)
Change in inventory	**(5,003)**	4,970
Cost of oil production	**25,262**	24,304
Total production for the period (boe)	**1,023,072**	1,273,751
Cost of oil production per boe (US$)	**24.7**	**19.1**

Net debt and gearing ratio

Net debt is defined as the Group's total borrowings (including current and non-current borrowings) less shareholders' subordinated debt, cash and cash equivalents and bank deposits. Management believes that net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding borrowings. The Group defines capital as the Group's total equity plus shareholders' subordinated debt. The Group calculates the gearing ratio (net debt to capital) as net debt divided by capital.

	2017 (US$ 000)	2016 (US$ 000)
Current borrowings	**12,500**	21,130
Non-current borrowings	**78,831**	255,118
Less: Shareholders' Subordinated Debt	**–**	(214,813)
Total third party borrowings	**91,331**	61,435
Less: Cash and cash equivalents and bank deposits	**(15,692)**	(12,977)
Net debt (1)	**75,639**	**48,458**
Total equity	**288,982**	(16,120)
Plus: Shareholders' Subordinated Debt	**–**	**214,813**
Capital (2)	**288,982**	198,693
Gearing ratio (1/2):	**26.17%**	**24.39%**

Capital expenditures

Capital expenditure is a useful indicator of the Group's organic expenditure on oil and gas assets and exploration and appraisal assets incurred during a period. Capital expenditure is defined as additions to property, plant and equipment and intangible exploration and evaluation assets excluding decommissioning asset additions, disposal and capitalised depreciation, less capitalised borrowing cost.

	2017 (US$ 000)	2016 (US$ 000)
Additions to property, plant and equipment	**65,741**	62,728
Additions to intangible exploration and evaluation assets	**3,152**	46,028
Less:		
Capitalised finance costs	**(1,258)**	(3,992)
Total	**67,635**	**104,764**

Being a responsible business and building trust

As an international oil and gas company, we recognise that we need to earn our social and legal licence to operate through a consistent track record of responsible, safe and effective performance.



Corporate social responsibility (CSR) lies at the heart of our business. We are here for the long-term and we understand that sustained commercial success and disciplined CSR go hand-in-hand.

Operating in the oil and gas sector demands that we adhere to the highest international standards to ensure we manage the impact of our business and its contribution to society. It is not just about acting in an ethical way, it is about understanding that CSR makes sound business sense and builds reputation.

It is also integral in helping us to:

- **Build** strong and productive relationships with our customers, partners and suppliers by understanding their needs
- **Manage** risk more effectively by strengthening our procedures and processes
- **Engage** our employees through a culture of collaboration, trust and safety
- **Improve** our performance by maintaining the integrity of our assets, our environment and our communities wherever we operate
- **Earn** trust to sustain our reputation long term.

Operating in a responsible and sustainable manner is essential to Energean Oil & Gas.

In addition to the expectations of stakeholders, CSR is a fundamental guiding principle of how we run our business. We believe that striving for the best possible CSR helps us to manage risks and fully capitalise on the opportunities presented to us in a changing world.

Our objective is to generate sustainable prosperity through our business operations.

We are therefore committed to conducting our operations responsibly, which means supporting local communities and caring for the environment, as well as looking after the health and safety of our employees.

CSR policy

Our CSR policy is rooted in our company values, guided by international standards and best practice, and driven by our aspiration for excellence in every area of our business.

Our Chief Executive is ultimately accountable for CSR, supported by our CSR Team. The Board has ultimate responsibility for reviewing and approving the CSR strategy and for monitoring our progress in achieving sustainability objectives through regular performance reviews and reporting.

All our business units are accountable for developing and implementing the CSR strategy and, where appropriate, our progress against our targets is independently assured.

Our approach to CSR

Corporate governance

We are committed to maintaining the highest standards of integrity and corporate governance practices in order to maintain excellence in our daily operations, and to promote confidence in our governance systems.

We aim to conduct our business in an open, honest and ethical manner.

Read more on pages 55–67



We focus our CSR activities in the following key impact areas:

Employees

We are focused on attracting, developing and retaining the best people and creating an environment where our employees can fulfil their true potential.

1

Read more on pages 40–41

Health & safety

The health and safety of our workforce remains our top priority. We invest in safety training and strive to meet the most stringent international standards. Our goal is to promote a safety culture where zero harm is of paramount importance.

2

Read more on pages 42–43

Environment

We are committed to conducting our business in an environmentally responsible way by mitigating risks and minimising the impact of our operations on the natural environment.

3

Read more on pages 44–45

Community involvement

As our business grows, so does our responsibility to the local communities where we operate. We work hard to support our local communities and work with them to make a real difference.

4

Read more on page 46

Creating a fair and inclusive culture

Our people are vital to the success of our business. They are our greatest asset and deliver sustainable value that makes a real difference. Guided by our values of responsibility, excellence, integrity, commitment, caring and engagement our people apply their skills and expertise every day to ensure we operate both responsibly and successfully.

Inclusivity and diversity

We create a fair and inclusive environment to attract the best people and keep them engaged and inspired to stay with us. By enhancing our employees' skills through training and development, we keep them motivated to progress through the business and achieve their personal objectives.

Energean is committed to equal opportunities and terms of employment, we offer competitive salary packages and the health and safety of all our employees is paramount in everything we do. We are fully committed to the elimination of unlawful and unfair discrimination and we value the differences that a diverse workforce brings to the business.

We believe in supporting diversity and creating an inclusive culture where all our people feel valued and able to fulfil their potential.

As of 31 December 2017, we employed 393 staff in six countries. The majority of the personnel is based in Greece, 365 staff, of which 336 are based in Kavala working onshore and offshore, and we are one of the largest employers of the prefecture. The remaining staff are employed in our offices in Israel, UK, Montenegro, Egypt and Cyprus.

Diversity

The Board of Directors is composed of nine members, one of whom is a woman. Out of the 393 employees of the Group, 32 are women.

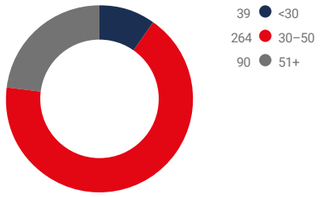
Employees by gender

	Male	Female
Board level	8	1
Senior management	14	4
Rest of staff	347	28

Age distribution

The majority of our employees (67%) are in the 30 to 50 age group, with the remaining 23% and 10% being in the age groups of 51+ and under 30 respectively.

Employee age distribution



Anti-corruption and bribery policy

The Group has an anti-corruption and bribery policy which sets out our responsibilities, as well as the responsibilities of those working for us, in observing and upholding our position on bribery. It also provides information and guidance to those working for us on how to recognise and deal with bribery and corruption issues.

Our Code of Conduct contains provisions relating to bribery and corruption which set out our policy of conducting all our business in an honest and ethical manner and in compliance with all applicable anti-bribery laws, including but not limited to all applicable local laws where the Group operates and the UK Bribery Act 2010 (the 'Bribery Act'), and to accurately reflect all transactions on the Group's books and records.

We take a zero tolerance approach to bribery and corruption and we are committed to acting professionally, fairly and with integrity in all our business dealings and relationships wherever we operate. Our Code of Conduct prohibits bribery and corruption in any form by employees, contract staff or industry partners working on our behalf.

Whistleblowing

As part of our commitment to conducting our business with honesty and integrity, the Group has adopted a Whistleblowing Policy that encourages the detection and reporting of malpractice throughout all levels of the organisation.

The Whistleblowing Policy takes into account the Whistleblowing Arrangements Code of Practice issued by the British Standards Institute and Public Concern at Work and is applicable to all individuals working within the Group including consultants and contractors. The Whistleblowing Policy sets out procedures for the reporting of any matter that a person would like to report in good faith and ensures that that person will be protected from any sanctions. At the time of reporting we have received no reports under our Whistleblowing Policy.

Our values

- **Responsibility** in all our actions and areas where we conduct our business
- **Excellence** in everything we do; deploying best practices to achieve profitable and sustainable growth
- **Integrity** by respecting our shareholders, employees and business; promoting transparency and accountability; cultivating a unique corporate sustainability culture
- **Commitment** to a talented workforce; investing in our people's development
- **Caring** for the environment; reducing our environmental footprint.
- **Engagement** with local communities; meeting their expectations and needs

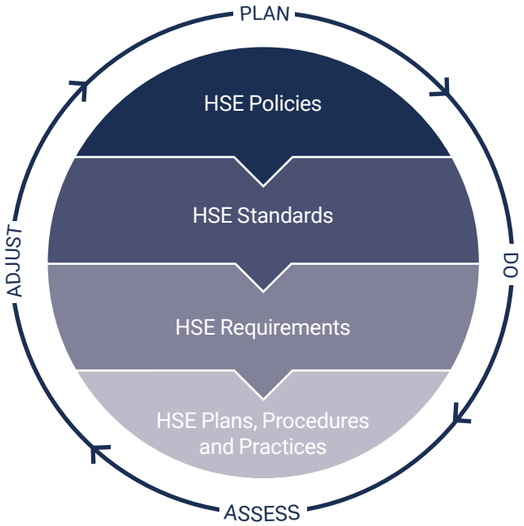
Building a culture of responsibility and safety

Energean is committed to protecting the health and safety of all individuals affected by its corporate activities, including employees, contractors and the general public.

We have established a comprehensive and integrated Health and Safety Management System (H&S MS) aligned with the requirements of international standards and European safety directives.

We are committed to the implementation, maintenance and continual improvement of our H&S MS and aim to achieve accreditation for international safety standards and best practices.

Our H&S MS is based on tried and tested, internationally recognised best practices in managing H&S risks in the E&P industry, structured around a classic 'Plan-Do-Assess-Adjust' cycle.



By implementing this structure we seek to ensure that we:

- Understand all hazards associated with our operations;
- Undertake activities to manage those hazards and minimise the risk levels;
- Measure the effectiveness of our HSE performance; and
- Adjust our plans and procedures in response to those assessments.

Key metrics monitored

- Total man-hours worked
- Number of Lost Time Injuries (LTI)
- Lost Time Injury Frequency (LTIF)
- Total Recordable Injury Rate (TRIR)
- Fatal Accident Rate (FAR)

Total man-hours worked

	2016	2017
Employees	570,410	**778,008**
Contractors	281,640	**161,280**

Total LTIs

	2016	2017
Employees	2	**3**
Contractors	0	**0**

LTIF*

	2016	2017
Employees	3.51	**3.86**
Contractors	0	**0**

* The number of lost time injuries (fatalities + LTIs) per million hours worked

TRIR*

	2016	2017
Employees	8.77	**10.28**
Contractors	3.55	**0**

* The number of recordable injuries (fatalities + LTIs + restricted work day cases + medical treatment cases) per million hours worked

FAR*

	2016	2017
Employees	0	**0**
Contractors	0	**0**

* The number of fatalities per 100 million hours worked

Corporate Major Accident Prevention Policy

The Board has approved a Corporate Major Accident Prevention Policy (CMAPP), recognising:

- Its responsibility to comply with the Offshore Safety Directive and with the Seveso Directive;
- That the nature of Energean's offshore oil and gas operations may give rise to major accidents;
- Its responsibility to control the risks of major accidents and to continuously improve these controls in line with advancements in technology and good oilfield practices;
- Its commitment — as laid out in the Code of Conduct — to achieve high standards of HSE performance and to make available all necessary resources to achieve these goals.

Energean controls risks of major accidents arising from its onshore and offshore oil and gas operations so far as is reasonably practicable, ensuring that such risks are within the 'acceptable' or 'tolerable' ALARP region (As Low As Reasonably Practicable).

'Stop work' policy

Any person employed and/or contracted by Energean may invoke the 'stop work' policy if they feel that any employee, a company asset or the local environment is at risk. There shall be no fault put on any employee calling for a 'stop work' order in good faith even if, upon investigation, the stop order proves to be unnecessary.

Leadership and commitment

HSE leadership and accountability for H&S starts with the CEO who takes all necessary steps to ensure that the highest possible level of H&S performance is achieved within the Company. We regard Health and Safety as a line responsibility and an integral part of the duties of all personnel.

Legal compliance

Compliance with all applicable H&S legislation and regulations is a fundamental requirement of the Energean H&S MS. All work carried out at our company offices and premises, and all work activities undertaken at project locations and operational sites, is carried out in accordance with applicable local laws and European regulations.

Competence management and training

Energean and its contractors implement an ongoing competence and assurance management scheme, and provide appropriate HSE training to all employees. Formal H&S training is provided to all employees and contractors either annually, or every 2–3 years, depending on the specific training required.

Operational framework and control

We develop, implement, monitor and review procedures and instructions for safe operation, enabling our adaptation to changes in operations, regulations, industry standards and advances in technology. The main components of this framework are:

- Pre-shift briefings and shift handovers
- Toolbox talks
- Site HSE inspections & audits
- Incident reporting & investigation
- Task risk assessments
- HSE meetings
- Permit to Work system
- Emergency response
- Safety inductions

Occupational health

We take all necessary steps to ensure the health of our employees and contractors. An annual health programme is implemented for all employees, which includes biochemical analysis, physical examinations, and heart and lung screenings. All employees and contractors hold medical certificates relevant to the requirements of their position. Private health insurance is provided to all employees, except in Israel where public health services are of a high standard.

Protecting our environment

Energean recognises the importance of understanding the impact of its activities on the environment and we are therefore working to continually improve our Environmental Management System. Our aim is to achieve accreditation for international environmental standards and best practices.

Our environmental responsibilities are addressed throughout the value chain and we are constantly investing in ways to reduce our carbon footprint and waste, as well as enhance our energy and water efficiency.

Environmental protection is a top priority and we are committed to ensuring that all necessary measures are being taken to minimise the possibilities of any environmental impact. Additionally, management and staff are committed to vigorous supervision and the implementation of applicable Greek and European legislation.



Marine Antipollution Response Drill, Prinos — Air quality monitoring

Key metrics monitored

- Greenhouse gas emissions
- Specific direct/indirect emissions
- Specific energy consumption
- Specific water usage
- Waste quantities

Environmental expenditure

	2016	2017
Total cost (€)	112,158	**525,318**

Crude oil production

	2016	2017
Product tn	178,209	**143,137**

Specific energy consumption*

	2016	2017
Electrical	338	**338**
Thermal	928	**1,202**

* KWh/product tn

Specific emissions*

	2016	2017
Direct	208	**262**
Indirect	297	**341**

* kg CO_2/product tn

Specific water usage*

	2016	2017
m^3/product tn	9,270	**10,096**

Non-hazardous waste disposal

	2016	2017
Total tn	398,190	**276,285**

Hazardous waste disposal

	2016	2017
Total tn	170	**1,191**

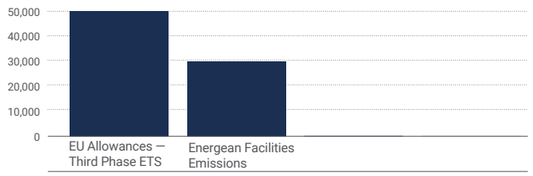
* It should be noted that increase of production due to the Prinos development plan will reduce the above specific values since the plant is designed to operate with higher production rates, with similar energy consumption data and raw material quantities.

Air quality

To ensure we meet all our environmental objectives we are continuously monitoring air quality. In the wider area of Thassos and Kavala, 12 stations monitor the total sulphation of the atmosphere on a monthly basis, and a central environmental station monitors H_2S, SO_2 and HC levels and meteorological parameters (wind speed and direction, ambient temperature, and relative humidity).

CO2 emissions*

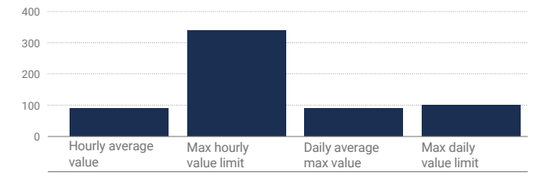
tn CO_2



* point sources

SO2 emissions**

mgr/m^3



** Air Quality Monitoring Station data

Marine environment

We have an excellent track record of environmental risk management. In 38 years of operation, in the sensitive environment of the Gulf of Kavala, no environmental damage has been recorded.

Our environmental policy and management are in line with all applicable national laws and European directives.

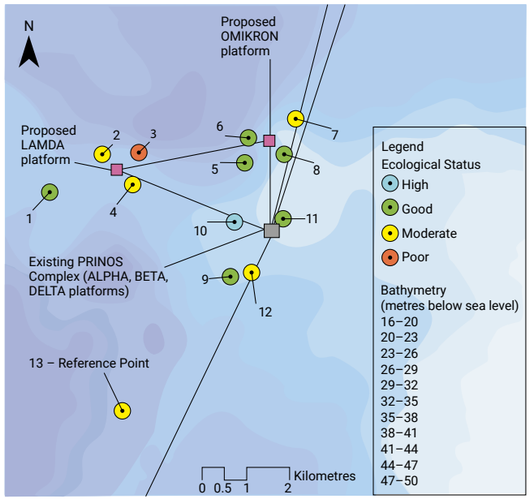
Our onshore and offshore water discharges are continuously monitored to meet the requirements of the Water Framework Directive, the Marine Strategy Framework Directive, the Barcelona Convention and the International Convention for the Prevention of Pollution from Ships (MARPOL).

Biodiversity protection

We aim to conserve the biological diversity of terrestrial, marine and avian migratory species throughout their range. We manage our operations by taking into account the fundamental ecological functions of wetlands and their economic, cultural, scientific and recreational value.

The Bonn Convention, the Ramsar Convention, the Convention on Biological Diversity, and the Birds and Habitats Directives are considered throughout the execution of environmental impact assessments and environmental monitoring plans.

An independent offshore specific study showed that benthic communities have not been affected by Energean's offshore operations in the Gulf of Kavala.



Marine contingency plan

We have developed and tested emergency response procedures for handling specific incidents such as oil spills. Our well-structured management plan, which includes regular, comprehensive training for staff and the necessary oil spill fighting equipment, ensures we have the confidence that we can manage any potential oil spill. The effectiveness of these emergency management procedures is demonstrated by the fact that we have never had to put them into practice.

Oil, tourism and the environment can co-exist

Since 2009, we have invested more than US$300 million in the Prinos oil field in the Gulf of Kavala. Our track record of zero environmental incidents during our operations in the Gulf demonstrates that heavy industry can be compatible with both the natural environment and the activities of local communities. Our ability to operate in environmentally sensitive areas is also reflected by the award of more than 10 blue flags by the Hellenic Society for the Protection of Nature (representing Greece in the International Foundation for Environmental Education) every year since 2008 to beaches and marinas in the areas surrounding the Prinos basin.

A socially conscious business

Energean seeks to promote and reinforce its relationships within the community. We are committed to supporting local causes that are close to the hearts of our employees and the communities in which we work, aspiring to make a real difference.

Community initiatives 2017

Education

Close collaboration with the Eastern Macedonia and Thrace Institute of Technology including providing industrial training, lectures, and internships for the MSc in Oil and Gas Technology and the MSc in Petroleum Engineering Technology.

Professors and students from the Polytechnic Institute of Thessaloniki's Aristotle University (School of Chemical Engineering) were hosted and given guided tours on our onshore installations (Sigma plant) in Kavala.

Lectures and seminars for University students and professionals in Athens and Thessaloniki, provided by Energean Oil & Gas.

Two scholarships for the two valedictorians of the graduating class of the academic year 2015–2016, Graduate Department (MSc in Oil and Gas Technology) of the Eastern Macedonia and Thrace Institute of Technology.

Professionals and executives from the Cyprus Hydrocarbons Company (CHC) were hosted and given guided tours at our Athens Headquarters and the Prinos Oil Field (our offshore installation in the Gulf of Kavala).

Society

During 2017, Energean's Athens Headquarters offered 1,445 meals for vulnerable people. We delivered these through our membership of the NGO 'BOROUME' ('We Can') with the motto 'Saving food – Saving lives'.

Donation of bulletproof vests as well as auxiliary logistical equipment to the Police Department of Kavala. Energean Oil & Gas supports the work of Kavala Police Directorate.

Donation of gift vouchers to 15 families in need, in order to have everything necessary to celebrate Easter in association with the Church of Saint Gregory the Theologian (Nea Karvali, Kavala).

Donation of heating oil to the Care Unit for the Elderly 'Agios Silas' ('Saint Silas'), a nursing home under the auspices of the Holy Metropolis Filippon, Neapoleos and Thassos.

Sports

Sponsorship of Kavala Basketball Team

Sponsorship of Kavala Football Club

Main Sponsor of the 3rd Olympia Marathon

Culture

Thassos Municipality Sponsorship of the 1st Christmas Village on Thassos island

Ioannina Prefecture, Kalpaki Sponsorship of 'Kalpakia', the Epirus Annual Memorial Day for World War II victims

Ioannina Prefecture, Support of the 1st Dodoni Festival

Risk management framework

Effective risk management is fundamental to achieving our strategic objectives and protecting shareholder value. The Directors have carried out a robust assessment of the Group's principal risks and a description of these risks, together with details of how they impact our strategy and how they are managed is provided on pages 49-52.

Overview

The Board has overall responsibility for determining the nature and extent of the significant risks it is willing to take in achieving its strategic objectives, and for ensuring that risks are managed effectively. A key aspect of this is designing and monitoring an internal control system in order to manage these risks.

In preparation for Admission, the Board established a risk management framework for the Group in order to identify, assess, control and monitor the risks to the business and allow it to achieve its strategic objectives.

The risk management framework sets out the inputs into the internal controls and risk management process and includes detail around the following matters:

- Risk reporting structure
- Identification
- Methodology and classification
- Risk appetite
- Group Risk Register
- Reporting and monitoring framework.

The Board has approved a Group Risk Register identifying significant risks of the following kinds:

- Strategic risk
- Health, safety and environmental risk
- Human resource risk
- Technology risk
- Regulation & compliance risk
- Operational and execution risk
- Financial and reporting risk.

The Board has put in place a monitoring system to ensure that risk management and all aspects of internal control are considered on a regular basis, and fully reviewed at least annually. The monitoring system assists in determining the nature and extent of the significant risks the Board is willing to take in achieving its strategic objectives.

Risk management processes

The Board and the senior management team use a combination of different and complementary skills to assess the risks facing the business. In determining its risk appetite, the Board considers a variety of information when reviewing the Group's operations and in approving key matters reserved for its decision. This information includes:

- Updates provided by senior management on key strategic and operational matters
- Discussion and approval by the Board of the Group budget (including its working capital)
- Information provided for the purposes of deciding whether to approve those significant matters which have been reserved for the Board;
- Group risk assessments facilitated by the Group's management and monitored by the Internal Audit function
- The reports of the external auditors.

Risk reporting

The Board has delegated to the Audit and Risk Committee the responsibility for reviewing the effectiveness of the Group's systems of internal control and risk management methodology.

As part of this review, the Audit and Risk Committee considers the principal risks facing the Group and the nature and extent of these risks, based on assessments by management and the Group's Internal Auditors. The Group outsources its Internal Audit function, which also provides independent assurance over the effectiveness of the systems of risk management and internal control. The detailed assessments are then consolidated to provide input into the overall Group risk assessment.



Principal risks and uncertainties

Strategy:

1 *Maximising output and cash flow from our producing assets*
2 *Developing Karish and Tanin*
3 *Capitalising on growth opportunities in the Eastern Mediterranean*
4 *Maintaining a disciplined financial framework*

Principal risks and uncertainties

This section describes the material existing and emerging risks which the Board believes could significantly impact the ability of the Group to meet its strategic objectives.

The Directors of the Company confirm that they have carried out a robust assessment of the principal risks facing the Company, including those that would threaten its business model, future performance, solvency or liquidity.

Principal Risk	Potential Impact	Mitigation
Strategic Risks		
Reserve replacement The Group's long term future success depends on its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. *Link to strategy:* 1	Generally, while the Group's current reserves are being depleted by production, unsuccessful exploration activities, such as dry wells, would mean that the Group would not be able to replace such reserves and the Group's revenue would decline. The Group may not be able to find or acquire additional reserves at acceptable costs which could have a material adverse effect on the Group's business, results of operations, financial condition and/or prospects. The Group's current reserves are being depleted at a low rate. Once production from Karish and Epsilon commences, depletion is expected to be significantly increased and hence the Group may have to increase the number of exploration wells drilled or discovered reserves acquired through M&A activity to maintain the same reserves position.	▶ Drilling of low risk, material exploration prospects in the Group's portfolio. ▶ Seeking new venture opportunities and other projects, including additions to the Group's exploration portfolio and the acquisition of additional stranded oil/gas Resources and conversion to Reserves via maturation of development projects. ▶ Continuing to manage exploration at an acceptable cost level. ▶ De-risking of the Group's existing exploration portfolio by acquisition of additional seismic data. ▶ Continuing to maintain a strong technical and commercial team with successful track record in exploration and marginal field development.
Geopolitical The geopolitical situation in Israel may adversely affect the Group's business. *Link to strategy:* 2	As the Group has assets located in and offshore Israel, political, economic and military conditions in Israel may directly affect the Group's business. The Group's development and/or future production operations with respect to the Karish-Tanin Development, although subject to security measures required by law and under the Lease requirements, could be specifically targeted.	▶ Active monitoring of the political, economic and social situation in Israel. ▶ Ensuring that the offshore facilities are appropriately equipped and protected. ▶ Monitoring and adhering to local laws and regulations.
Health, Safety and Environmental Risks		
Health, Safety and the Environment The Group is obliged to comply with health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations. *Link to strategy:* 1 2	The Group operates in an industry that is inherently hazardous and consequently subject to comprehensive regulation. Although the Group considers that it has adequate procedures in place to mitigate operational risks and keeps these under review, there can be no assurances that these will be adequate and failure to adequately mitigate risks may result in loss of life, injury, or adverse impacts on the health of employees, contractors or third parties or the environment. Failure, whether inadvertent or otherwise, by the Group to comply with applicable legal or regulatory requirements may give rise to significant liabilities and may result in loss of life, injury, or adverse impacts on the health of employees, contractors and third parties or the environment.	▶ Compliance with the Group's Health, Safety and Environment ('HSE') policy which observes local and national, legal and regulatory requirements and generally applies best practices where local legislation does not exist or where environmental regulation does not presently occur. ▶ Ongoing monitoring of the changes in relevant legislation and regulation. ▶ Implementation, maintenance and continual improvement of the applied HSE Management System. ▶ Accreditation for Environmental International Standard ISO 14001 for all existing installations. ▶ Continuous monitoring of air quality in existing plans' locations. ▶ Improvement of oil spill fighting equipment and services. ▶ Implementation of an ongoing competence assurance and assessment scheme. ▶ Implementation of an internal annual safety training for all onsite personnel and contractors. ▶ Incidents' investigation and communication of lessons learned. ▶ KPIs monitoring and management review of HSE performance. ▶ Implementation of a health monitoring programme and personnel fitness for workers onsite.

Principal Risk	Potential Impact	Mitigation
Project Execution & Production Operations Risks		
Project Execution The Group's success will be partly dependent upon completing the Karish-Tanin Development on budget and on schedule. *Link to strategy:* 1 2	The Karish-Tanin Development is in its early stages. Whilst the design and execution strategy have been developed so as to mitigate risk, in particular in a country with a strong environmental lobby, by carrying out processing offshore, there remain risks in ensuring that project delivery is on budget and on schedule. Any delay in project delivery could have an impact under the Group's Gas Sales and Purchase Contracts.	▶ Strong compliance with local law requirements, regular interface meetings with the authorities and pro-active engagement with local stakeholders, to ensure environmental approvals are obtained in a timely manner. ▶ Disciplined lump sum, turnkey engineering, procurement, construction, installation and commissioning 'EPCIC' Contract with TechnipFMC for the construction of the FPSO and subsurface facilities (which Contract includes liquidated damages, including for the event of delay). ▶ Monthly reporting on the status, risks, opportunities and budget of the Karish-Tanin development. ▶ Effective contract management, with a focus on minimising variations and close management of contingencies and variable items. ▶ Focus on the critical path and regular progress meetings.
Production The Group's success will be partly dependent upon continuing production from Prinos. *Link to strategy:* 1	The Group's current oil and gas production and related revenue are obtained entirely from the Prinos basin, located offshore in northeast Greece. The Group is therefore exposed to the effect of disruption, delays or interruptions of production from wells in this area.	▶ Continuous focus on and investment in HSE. ▶ Committed in house reservoir engineers and production technologists working on Prinos reservoir management, supplemented with outsourced consultants/experts. ▶ Continuous review of well design and performance, in particular with a view to minimise unexpected or additional well maintenance. ▶ Monthly reporting on the status, risks, opportunities and budget of the Prinos development. ▶ Management and maintenance of facilities, with a focus on ensuring that unplanned work-overs, shutdowns and expenditure are minimised. ▶ Compliance with asset licence and applicable laws and regulations. ▶ Continuous and rigorous focus on cost control.
Major cyber or information security incident *Link to strategy:* 1 2	A cyber-attack could compromise the Group's network and have a disruptive or destructive impact resulting in stopped production, explosion or loss of life. Any loss or theft of confidential information could lead to loss of competitive advantage and intellectual property and reputational damage.	▶ Continuous implementation and monitoring of the Company's IT Security Policy, which includes measures to protect against cyber-attacks. ▶ Vulnerability Assessment and Penetration Testing. ▶ Employee awareness of confidentiality through internal policies (including the Group's Corporate Culture and Business Ethics policy) and awareness training. ▶ Control of disclosures and protection of any disclosed confidential information in third party contracts.

Principal Risk	Potential Impact	Mitigation
Financial Risks		
Compliance with Financial Covenants The Group has secured loan agreements and is subject to restrictive debt covenants and security arrangements that may limit its ability to finance its future operations and capital needs and to pursue business opportunities and activities. Breach of financial covenants may lead to default and/or liquidity risk. *Link to strategy:* 4	Under the terms of the Reserve Based Lending ('RBL') Senior Facility Agreement and the Subordinated Facility Agreement and the Karish-Tanin Project Financing, the Group must comply with a number of covenants including financial maintenance covenants and restrictions on, among other matters, dividends and other distributions, cash movements, capital expenditure, additional future borrowings and indebtedness, and disposals and acquisitions. The breach of any of these covenants could result in part of the loan amounts becoming unavailable or to an event of default, in which case all amounts owed to the lenders would be due and payable immediately.	▶ All loans are project based, not corporate loans, that have been sized and structured on conservative price, cost and production assumptions. ▶ Regular monitoring of financial covenants on an actual and forecast basis as part of the monthly reporting to management and the Board. ▶ Adhering to the Facility Compliance Calendar, which outlines covenant requirements, due dates and the frequency of reporting.
Treasury and trading The Group is exposed to treasury and trading risks, including foreign exchange and commodity price risk. *Link to strategy:* 4	The Group is exposed to changes in currency values as a result of its international operations in various foreign currencies. The key sources of the risk include loan agreements denominated in the U.S. dollar, sales of crude oil remunerated in U.S. dollar, ongoing operating costs and capital expenditures incurred in EUR, USD and to a lesser extent GBP and NOK. The Group is exposed to commodity prices in relation to its sales and revenues under the crude and gas sales, which are subject to variable market factors. A decrease in these commodity prices could significantly impact the Group's cash flows and results.	The Group has a centralised Treasury function which manages currency exchange, interest rate and commodity risks, with mitigations including: ▶ **Currency risk** – Regular updates and revisions of short and long term expenditure budgets and cash flow projections, applying 15% sensitivity on EUR: USD movements – Short term EUR: USD hedging for fixed inelastic EUR denominated expenditures. – Negotiation of large capital expenditure, commitments and contractual obligations in USD denominations. The Group plans to exercise the option under the Technip EPCIC contract and fix the non USD component of the payment plan in USD. – All Group loans are USD denominated. ▶ **Commodity price risk** – The Group has hedged 450 thousand bbls of production for 2018 at a price of approximately USD69.4/bbl. – The Group actively monitors oil price movements and will proceed in hedging part of its proved and producing barrel sales profile for a tenor of no more than 12 months. – All Karish-Tanin gas contracts are based on pricing formulas which include floor prices; that ensures a minimum price for gas sales whatever the market conditions or pricing formulas outcome. – Group's debt facilities have been sized and structured on conservative oil and gas price assumptions versus the prevailing market prices.

Principal Risk	Potential Impact	Mitigation
Financial Risks		
Liquidity risk and restricted funding The Group not having adequate liquidity and/or access to the necessary funding sources in order to meet its minimum opex, capex and financing commitments as well as its growth and expansion plans. *Link to strategy:* 4	Lack of necessary liquidity and access to funding may materially impact the Group's plans to develop its existing assets, meet production targets and execute its strategic growth plan.	▶ At least monthly monitoring of 6-18 month cash flow projections under a number of reasonable worst case assumptions, which include downside sensitivities on oil price, cost and production levels. ▶ Optimisation of debt capital structure. ▶ Strong long term relationship with major international and local financial institutions. ▶ The Karish-Tanin development has secured funding to First Gas by a combination of committed equity funding and the Karish-Tanin project finance. ▶ Epsilon development has secured funding to First Oil by a combination of ongoing operating cash flow from Prinos field and the RBL Facility. ▶ Major turnkey EPCIC contracts for both Karish-Tanin and Epsilon development to minimise the risk of cost overruns and ensure adequate liquidated damages are payable in case of project execution delays.
Counterparty Risk The Group being exposed to delayed payment, counterparty default or suspension or termination of sales. *Link to strategy:* 4	All of the Group's production of crude oil from the Prinos basin is currently sold to a single Buyer, BP, under a long-term offtake agreement. The Group is consequently reliant on BP for substantially all of its revenue. If the offtake agreement with BP was terminated, the Group would need to negotiate and enter into a new offtake contract. During any such negotiations, the Group may not be able to sell any of its oil from the Prinos basin, which would have an adverse effect on the Group's business, results of operations, financial condition and/or prospects.	▶ In Q1 2018, the offtake agreement was extended to 2025 on same terms. ▶ The Group has built a strong relationship with BP and the contractual terms have been applied since 2013 without disputes and/or payment defaults and/or lifting delays. ▶ Focus on maintaining delivery of production. ▶ BP is an investment grade A- credit rated company with minimal risk of being unable to meet its lifting and payment obligations under the Prinos offtake agreement.
Governance and Compliance Risks		
Fraud, bribery and corruption The Group has an obligation to comply with fraud, anti-bribery, anti-corruption and anti-money laundering laws and violations of these laws expose the Group and / or its employees to criminal ramifications. *Link to strategy* 1 2 3 4	The Group is exposed to bribery and corruption risk through its business operations. Any instances of non-compliance with applicable laws and regulations, including those laws around fraud, anti-bribery, anti-corruption and anti-money laundering, could damage the reputation of the Group. In addition, these could result in litigation, regulatory action and fines which may have a material adverse impact on our cash flows and the financial condition of the Group.	▶ Strong oversight and leadership from the Executive Management and the Board. ▶ Robust framework of controls to monitor all payment approvals. ▶ Compliance with governance policies, including the Group's Anti-Corruption and Bribery Policy, which sets out the Group's responsibilities, as well as those of its employees, in observing and upholding its position on bribery. The policy also provides information and guidance to those working for the Group on how to recognise and deal with bribery and corruption issues. ▶ Anti-Bribery training of Group personnel. ▶ Compliance with the Group's Corporate Culture and Business Ethics Policy which includes the Group's policy of conducting all its business in an honest and ethical manner and in compliance with all applicable laws, including but not limited to all applicable local laws where the Group operates and the Bribery Act 2010.

Viability statement

The Directors have assessed the viability of the Group over a three-year period to December 2020, taking account of the Group's current position and the potential impact of the principal risks documented in this report. To support the Viability Statement the Directors have prepared monthly projected cash, profit, balance sheet and headroom under financing facilities available for 36 months ending 31 December 2020 supported by the basis of preparation, the underlying assumptions, the computation of financial covenants applicable during the period and sensitivity analysis.

The Directors have determined that the three-year period to December 2020 is an appropriate period to underpin their Viability Statement. In the first quarter of 2021 the Group's Karish asset is expected to be on-stream delivering a long-term source of funds.

For the purpose of our viability assessment a three-year financial model was used as a base-case scenario. Considering the shorter assessment period as compared to the impairment testing model, we assessed that the base-case scenario is most sensitive to the following assumptions:

- Implementation of the drilling programme in Prinos, which is based on the most recent NSAI reserve report. The drilling programme is based on the required programme to produce all 2P reserves and does not cover any of the contingent resource base;
- No commercial gas is assumed to be produced; and
- Having signed the US$1.275bn Facility Agreement and raised the equity required to develop Karish through a premium listing on the London Stock Exchange, the Group has limited its balance sheet and capital expenditure exposure to the project over the period to first quarter of 2021 when the asset will be ready to come on-stream.

For the purpose of sensitivity testing, several principal risks and uncertainties were selected (from those described on pages 49–52), which were deemed to have the highest potential financial impact on the Group's future performance and liquidity, taking into account prior period assessments.

The effect of those principal risks and uncertainties or their combination on the base-case scenario were analysed within following scenarios:

- Deterioration in the business and market environment: taking into account that the oil price assumptions applied in the base case scenario were based on conservative projections by institutional analysts, this scenario was aimed at analysing the sensitivity to a further 15% reduction in the oil prices over the period of assessment;
- a 20% decrease in development of proved and probable reserves (2P): and analysing the sensitivity to a further 15% reduction in the production volumes over the period of assessment;
- a Reasonable Worst Case (RWC) scenario: a combination of 15% reduction in the base case price, 20% decrease in production volumes together with impact of a 2 month delay in production from new wells to come on stream during the forecast period;

The scenarios took into account the availability and likely effectiveness of any mitigating actions that are in place or could be implemented such as hedging, additional funding options and further rationalisation of our cost base including cuts to discretionary capital expenditure.

Based on the results of the analysis the Board of Directors has a reasonable expectation that the Company will be able to continue in operation and meet its liabilities as they fall due over the three-year period of its assessment.

Corporate Governance

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Chairman's letter



Dear Shareholders,

I am pleased to welcome you to our first Corporate Governance report on behalf of the Board. In this, we provide a description of our governance arrangements and explain how we will apply the main principles of the provisions set out in the UK Corporate Governance Code (the 'Governance Code') issued by the Financial Reporting Council (FRC). We believe it is important that the governance structure supports the success of the Company's strategy and ensures the creation and preservation of shareholder value, as well as benefiting other stakeholders.

I look forward to working with the Board, management and all of our stakeholders as we become a leading independent oil and gas exploration and production company in the Eastern Mediterranean.

The Board and governance

Our Board was formed in 2017, following incorporation of the Company and prior to the IPO in March 2018. In preparation for listing, the Board reviewed and expanded its policies, where necessary, with the aim of strengthening the Group's governance framework.

The Board plays a vital role in developing and maintaining the Group's culture and values by setting the 'tone from the top', determining the behaviours expected by the Board and ensuring that ethical standards are maintained. In doing so, the Board aims to strike the right balance between entrepreneurial leadership and the prudent and effective management of risk, both of which are essential to maintaining a sustainable business and creating value for shareholders.

Diversity

The Board understands the benefits of diversity in maintaining and improving the quality of performance and all Board appointments are made against objective criteria and with due regard to the benefits of diversity, in all senses.

The Board will be establishing a Board diversity policy in 2018 and we look forward to presenting the key principles of the new policy and how it has been implemented in the 2018 Annual Report.

Board evaluation

As the IPO took place in March 2018, the Board did not undertake an evaluation during 2017. However, the Board has discussed the benefits of undertaking a review and an internal review of Board effectiveness will be undertaken in 2018. The internal review will focus on the governance policies and procedures which we have introduced and will play a key role in identifying any areas for further improvement in our corporate governance framework.

Engagement with shareholders

We place emphasis on active engagement with our shareholders and aim to maintain open and transparent communication. We laid the foundations for this ongoing shareholder dialogue as we progressed through the listing process, and look to continue this through 2018 and beyond.

Looking ahead, I expect 2018 to be an important year for Energean as the Group continues to grow and focus on the development of Karish and Tanin. In this context, developing and maintaining the high standards of governance established to date will be of critical importance.

I look forward to engaging with many shareholders throughout the year and welcoming all shareholders to our first Annual General Meeting on 28 June 2018.

Simon Heale
Chairman
30 April 2018

Board of Directors

An experienced Board with extensive expertise in sector, financial, HSE and capital markets.



Simon Heale
Non-Executive Chairman

Independent
On Appointment

Commencement of Appointment
July 2017

Committee Membership
- Nomination and Governance (Chair)

Key Skills & Experience
Simon Heale is a Chartered Accountant with a degree in Philosophy, Politics and Economics from Oriel College, Oxford.

Simon has significant business operations and management experience gained through a diverse range of industries, previously serving as chairman of Kaz Minerals (previously known as Kazakhmys plc) until December 2017.

He has also served on the boards of Carlton Commodities Capital Corporate Member Limited from 2011 to 2016, Coats plc from 2011 to 2014, Morgan Advanced Materials from 2005 to 2014, PZ Cussons from 2008 to 2013 and Panmure Gordon & Co from 2010 to 2011.

Simon has extensive experience in senior executive roles, including as chief executive of the London Metal Exchange from 2001 to 2006, as chief operating officer of Jardine Fleming Ltd from 1999 to 2001, and as deputy managing director at Cathay Pacific Airways from 1994 to 1997.

Current External Appointments
- Chairman of GMS.
- Chairman of Marex Spectron.



Matthaios (Mathios) Rigas
Chief Executive Officer

Independent
Not Applicable

Commencement of Appointment
May 2017, previously the CEO of the Group since 2007

Committee Membership
Not Applicable

Key Skills & Experience
Mathios Rigas holds a degree in Mining and Metallurgical Engineering from the National Technical University of Athens and an MSc / DIC degree in Petroleum Engineering from Imperial College London.

Mathios has 20 years of investment banking and private equity experience and is a founding shareholder of the Group.

During the years 2001 to 2007 he set up, and was managing partner of, Capital Connect Venture Partners, a private equity fund in Greece with investments in innovative enterprises in IT, healthcare, waste management and food industries.

From 1999 to 2001 Mathios was in charge of Piraeus Bank's shipping division, and from 1993 to 1999, he was vice president of shipping, energy & project finance at Chase Manhattan Bank. He was formerly the chairman of the board of Tyres Herco S.A. and MAVIN S.A. in Greece.

Current External Appointments
Not applicable



Panagiotis (Panos) Benos
Chief Financial Officer

Independent
Not Applicable

Commencement of Appointment
May 2017, previously the CFO of the Group since 2011

Committee Membership
Not Applicable

Key Skills & Experience
Panos Benos is a Chartered Accountant and holds an MSc in Shipping, Trade and Finance from Cass Business School.

Panos has 15 years of international experience in the oil and gas sector, both in banking and industry, with a long track record of upstream financing in emerging markets.

He was previously a director in the oil and gas team in London with Standard Chartered Bank, delivering a number of award winning projects and acquisition finance deals in Africa, Asia and the Middle East.

Prior to that Panos worked for ConocoPhillips from 2002 to 2006, where he held positions in European treasury, North Sea economics and international downstream with a focus on the North Sea, Central Europe and the Middle East. He commenced his career at Royal Bank of Scotland in shipping finance.

Current External Appointments
Not applicable



Andrew Bartlett
Senior Independent Director

Independent
Yes

Commencement of Appointment
August 2017

Committee Membership
- Audit and Risk (Chair)
- Nomination and Governance
- Remuneration

Key Skills & Experience
Andrew Bartlett holds an MSc in Petroleum Engineering from Imperial College London.

Andrew has over 30 years' experience in the upstream oil and gas industry.

Andrew served as the chairman and non-executive director of Azonto Energy from 2013 to 2015.

He was also previously the global head of Oil & Gas M&A and Project Finance for Standard Chartered Bank between 2004 and 2011. Prior to this, Andrew worked on the trading and derivatives desk of Standard Bank in South Africa.

Before joining the investment banking industry, Andrew worked for Royal Dutch Shell between 1981 and 2001, as a petroleum engineer and development manager, where he gained extensive experience in the operation of oil and gas fields.

Current External Appointments
- Non-Executive Director for Africa Oil Corporation
- Non-Executive Director for Impact Oil & Gas
- Adviser to Helios Investment Partners LLP



Karen Simon
Independent Non-Executive Director

Independent
Yes

Commencement of Appointment
September 2017

Committee Membership
- Health, Safety and Environment

Key Skills & Experience
Karen Simon holds a Masters in International Management, an MBA and BA in Economics & International Studies.

Karen has been with J.P. Morgan for over 34 years.

Her career includes senior roles in Oil & Gas, Debt Capital Markets and Private Equity coverage.

Karen was the Head of Financial Sponsor Coverage for J.P. Morgan in both New York and in London from 2007 to 2016, serving further as Global co-head including Asia.

Prior to this, she was co-head of Debt Capital Markets for EMEA and spent the first 15 years of her career in various positions in the Oil & Gas division in Houston and London.

Current External Appointments
- A Vice Chairman of Investment Banking, J.P. Morgan
- Non-Executive Director for Aker ASA
- Board Member of the non-profit Dallas Women's Foundation

Board of Directors



Efstathios (Stathis) Topouzoglou
Non-Executive Director

Independent
No

Commencement of Appointment
May 2017

Committee Membership
- Nomination and Governance

Key Skills & Experience
Stathis Topouzoglou holds a B.A. in Business Administration and Economics from the University of Athens, Greece.

He is a founding shareholder of the Group. Stathis is also co-founder of Prime Marine Corporation, a leading worldwide product tanker company and major global provider of seaborne transportation for refined petroleum products, LPG and ammonia.

Stathis has more than 35 years of experience in founding and growing companies in the energy transportation sector.

Current External Appointments
- Chief Executive Officer and Managing Director of PRIME
- Chairman of FSL Trust



Ohad Marani
Independent Non-Executive Director

Independent
Yes

Commencement of Appointment
July 2017

Committee Membership
- Audit and Risk
- Remuneration (Chair)
- Health, Safety and Environment

Key Skills & Experience
Ohad Marani holds an MA in Public Administration from Harvard University. He also hold an MBA (major in Finance) and a BA in Economics, both from the Hebrew University of Jerusalem.

Ohad was Chief Executive Officer of the Israel Land Development Company Energy Ltd from April 2010 to September 2015, Chairman of the board of Emmanuelle Energy from 2010 to 2015, and Chairman of the board of Israel Natural Gas Lines Ltd from 2008 to 2010.

He was the Executive Chairman of the board of ORL Ltd from 2004 to 2007.

Ohad has also served in the Israeli government, including as Director General of the Israeli Finance Ministry from 2001 to 2003, Director General of the Budget Department of the State of Israel from 2000 to 2001, and Minister of Economic Affairs at the Israeli Embassy in Washington from 1995 to 2000.

Current External Appointments
- Board member of Bank Leumi of Israel Ltd.
- Member of the Investment Committee of Israel's Infrastructure Fund



Robert Peck
Independent Non-Executive Director

Independent
Yes

Commencement of Appointment
July 2017

Committee Membership
- Audit and Risk
- Remuneration
- Health, Safety and Environment (Chair)

Key Skills & Experience
Former Ambassador Robert Peck holds a B.A. in History and Journalism from Concordia University in Montréal.

Robert was Canada's Ambassador to Greece and High Commissioner to the Republic of Cyprus from 2011 to 2015, Chief of Protocol of Canada from 2007 to 2010, and Canada's Ambassador to the People's Democratic Republic of Algeria from 2004 to 2007.

He was Senior Advisor in the Human Resources Bureau at Global Affairs Canada, a department of the Government of Canada, from 2015 to 2017.

During a two-year leave of absence from the Government of Canada, Robert was Director of Corporate Communications and Investor Relations at CAE Inc., from 2000 to 2002.

He was also Counsellor to the Canadian Embassy in Greece from 1995 to 1998.



David Bonanno
Non-Executive Director

Independent
No

Commencement of Appointment
May 2017

Committee Membership
- Remuneration

Key Skills & Experience
David Bonanno graduated cum laude from Harvard University with a B.A in Psychology.

In 2008, David joined Third Point, where he is managing director, focusing on special situation opportunities in the US and Europe and where he acts as the primary investment professional responsible for all Third Point's Hellenic Recovery Fund L.P. activities in Greece.

Prior to joining Third Point, David was an associate in the private equity and distressed investments group at Cerberus Capital Management, L.P from 2006 to 2008.

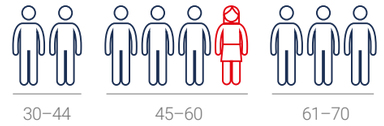
Prior to this, he was an analyst in the restructuring and reorganisation advisory group at Rothschild Inc. from 2004 to 2006.

Current External Appointments
- Managing Director, Third Point

Board diversity

The mix in our membership

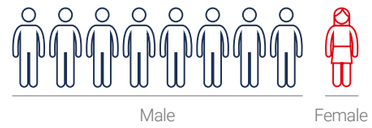
Board diversity by age (years)



Board diversity by nationality



Board diversity by gender



Corporate governance report

Statement of compliance

The Board is committed to the highest standards of corporate governance. Since Admission on 21 March 2018, the Board has and will continue to comply with the provisions of the UK Corporate Governance Code ('the Code'). In this report, we describe our corporate governance arrangements and explain how the Group applies the principles of the Code. The Code is available from www.frc.org.uk.

Directors

New Directors were appointed to the Board in 2017 in anticipation of the admission of the Company's ordinary shares to the premium listing segment of the FCA and to trading on the London Stock Exchange's main market of listed securities. Following the appointment of the Independent Non-Executive Directors in 2017, the Board believes it has an appropriate balance of skills and experience and meets Code provision B.1.2 for at least half the board, excluding the Chairman, to comprise Independent Non-Executive Directors.

The Board

The Board plans to meet on at least five occasions during the course of 2018 to review trading performance and budgets, funding, to set and monitor strategy, examine acquisition opportunities and report to shareholders. The Board may also meet at other times at the request of one or more of the Directors. The Board has a formal schedule of matters that can only be decided by the Board, and this schedule is reviewed by the Board each year. The key matters reserved are the consideration and approval of:

- Business plan and budgets
- Group strategy
- Performance review
- Operation as a listed company
- Financial reporting and controls
- Distributions and dividends
- Changes in capital structure
- Capital expenditure
- Board membership
- Acquisitions and disposals
- Material contracts
- Material tenders
- The appointment and removal of internal and external auditors
- Material litigation
- Compliance with statutory and regulatory obligations
- Approval of press releases
- Internal controls and risk management
- Significant transactions
- Executive remuneration
- Delegations of authority

The roles of Chairman and Chief Executive Officer are separate and the responsibilities of the Chairman and Chief Executive Officer are independently defined. It is the Chairman's responsibility to provide leadership of the Board and set the board agenda as well as to ensure that the Board is provided with accurate, timely and clear information in relation to the Group and its business. The Chief Executive Officer is responsible for setting the overall objectives and strategic direction of the Group as well as having day-to-day executive responsibility for the running of the Company's businesses. The Chairman and Chief Executive Officer will share responsibility for the representation of the Company to third parties.

Non-Executive Directors

The Non-Executive Directors have a broad range of business and commercial experience. They provide independent and constructive challenge to the Group and monitor the performance of the Chief Executive Officer and the Chief Financial Officer against the Group's strategy and key objectives.

Each appointment is for an unlimited term, subject to being re-elected as a director at each annual general meeting. A Non-Executive Director or the Company may terminate the appointment at any time upon three months' written notice. These appointments are subject to the provisions of the Articles, the UK Corporate Governance Code, the Companies Act and related legislation.

The role of the Senior Independent Director, Andrew Bartlett, is to provide a sounding board for the Chairman and to serve as an intermediary for the other Directors when necessary. The Senior Independent Director is available to shareholders if they have concerns which contact through the normal channels of Chairman, Chief Executive Officer or Chief Financial Officer has failed to resolve or for which such contact is inappropriate.

Independence of Directors

The Board comprises a Non-Executive Chairman, who was independent on appointment, two Executive Directors and six Non-Executive Directors. The Company considers all of the Non-Executive Directors to be independent within the meaning of 'independent' as defined in the Code, other than David Bonanno and Efstathios Topouzoglou.

While each of Mr Bonanno and Mr Topouzoglou are considered to be independent in character and judgement, David Bonanno is not deemed to be independent by reference to the criteria set out in the Code as a result of representing Third Point Hellenic Recovery (Lux) S.Á. R.L., which holds approximately 26.7% of the shares of the Company, while Efstathiou Topouzoglou is not deemed to be independent by reference to the criteria set out in the Code as a result of owning in aggregate (as an individual and by his indirect holdings in both Oilco Investments Limited and HIL Hydrocarbon Investments Limited) approximately 11.7% of the shares of the Company.

Leadership structure

Audit and Risk Committee	Nomination and Governance Committee	Remuneration Committee	Health, Safety and Environment Committee
Chair Andrew Bartlett	**Chair** Simon Heale	**Chair** Ohad Marani	**Chair** Robert Peck
Members Ohad Marani Robert Peck	**Members** Andrew Bartlett Efstathios Topouzoglou	**Members** Andrew Bartlett David Bonanno Robert Peck	**Members** Ohad Marani Karen Simon

Appointments to the Board

The Nomination and Governance Committee reviews the structure, size and composition of the Board and makes recommendations to the Board about any changes required. The Executive Directors, Mathios Rigas and Panos Benos, were appointed as directors on incorporation of the Company.

Board committees

The Board has established four committees made up principally of Independent Non-Executive Directors and all appointments to these committees shall be for an initial period of up to three years and may be extended by no more than two additional three year periods. These committees are:

- Audit and risk committee (pages 62–63)
- Nomination and governance committee (page 64)
- Health, safety and environment committee (page 65)
- Remuneration committee (pages 66–67)

The page numbers above denote the location of each committee report which describes the composition and focus for each of the committees. The terms of reference of the committees have been drawn up in accordance with the provisions of the Code. A copy of each committee's terms of reference is available from the Company Secretary and can be found at www.energean.com.

Board effectiveness

Evaluations

The Board is committed to undertaking regular reviews of its effectiveness and believes such a process can add value to the way the Board, committees and individual directors operate.

The Board plans for a formal, internal evaluation of its own performance, that of its committees and the individual directors to take place for the year 2018. More generally, it will also review the Group's overall corporate governance arrangements, and the Group will report on these matters in the 2018 Annual Report.

Training and development

Board members are provided with ongoing training and development opportunities.

Development needs are discussed during annual performance reviews with the Chairman. In 2017, Board members were provided with training on a number of topics including their obligations under the Listing Rules, Prospectus Rules, The Disclosure Guidance & Transparency Rules and the Market Abuse Regulation.

Induction

On joining the Board all new Directors will receive an induction programme that is tailored to their individual requirements. The induction schedule is facilitated by the Company Secretary in consultation with the Chairman and the new Director.

The objective of each induction programme is to provide an overview of the business, strategy, finances, the Group's history and culture and values and to ensure that the new Director gains sufficient knowledge of the business to allow them to carry out their role effectively.

Relationship with shareholders

Engagement with shareholders

We are committed to regular dialogue with our shareholders and the wider investment community and this process commenced with the IPO preparations. Ongoing communications will be through regulatory announcements, regular meetings, presentations, investor conferences and ad hoc events.

Shareholders can access details of the Group's results and other new releases through the London Stock Exchange's Regulatory News Service, and all news releases are published on the Investors and Media sections of the Group's website: www.energean.com.

Annual General Meeting

The 2018 AGM will be held on 28 June 2018 and shareholders will receive presentations setting out the key developments in the Group and have an opportunity to ask questions of the Board.

A poll will be used to for all resolutions and the final results will be announced via the London Stock Exchange Regulatory News Service and on the Group's website.

Audit and risk committee report



I am pleased to present this Audit and Risk Committee Report for the year ended 31 December 2017, which sets out the role of the committee and key areas of focus for 2018 since the committee recently became effective in March 2018.

Membership of the committee

The other members of the Audit and Risk Committee are Ohad Marani and Robert Peck.

The committee's members are all Independent Non-Executive Directors, and therefore the composition of the committee complies with the Code. Members' skills and experience are documented on pages 56–59. The Board is satisfied that the committee meets the requirement to have recent and relevant financial experience and that as a whole we have sufficient experience of the oil and gas sector.

Role of the committee

The Audit and Risk Committee's role is to assist the Board with discharging its responsibilities in relation to financial reporting, including monitoring the integrity of the Group's annual and half year financial statements, reviewing the Group's accounting policies, reviewing the Group's internal financial controls, reviewing and monitoring the scope of the annual audit and the extent of the non-audit work undertaken by external auditors, advising on the appointment of external auditors and reviewing the effectiveness of the internal audit, whistleblowing and fraud systems in place within the Group.

The Audit and Risk Committee shall additionally review the Group's capability to identify and manage new types of risk, and keep under review the Group's overall risk assessment processes that inform the Board's decision making.

The Audit and Risk Committee will consider annually how the Group's internal audit requirements shall be satisfied and make recommendations to the Board accordingly as well as on any area it deems needs improvement or action.

Meetings

The Audit and Risk Committee became effective upon Admission in March 2018, therefore no meetings were held in 2017. The committee plans to meet three times in 2018. Any member of the committee, the Company's external auditors or its internal auditors may however request a meeting if he/she considers that one is necessary or expedient.

Key matters considered in relation to the consolidated financial statements

The Audit and Risk Committee focused on a number of key judgements and reporting issues in the preparation of the full year results and the annual report. In particular, the committee considered, discussed and where appropriate challenged:

- As at 31 December 2017, the Group held a commitment to acquire 70% of preference shares in Energean Israel Limited from the Founders[1] (50%) and Kerogen Investments No. 38 Limited (20%). A derivative asset of USD 93.4 million was recognised in the accounts, using an estimate as at 31 December 2017 of the likelihood of the IPO being successful and the exercise price. The committee challenged and supported this valuation. The IPO and consequently this transaction were successfully executed after the end of the accounting period.
- The viability statement in the 2017 annual report and the going concern basis of accounting including consideration of evidence of the Group's capital, liquidity and funding position. The committee considered the assessment of principal risks, assessed the Group's prospects in light of its current position and reviewed the disclosures on behalf of the Board. The committee supported the viability statement and the Directors' going concern conclusion.

Assessment of annual report

A requirement of the Code is that the annual report is fair, balanced and understandable and provides the information necessary for shareholders to assess the company's position and performance, business model and strategy. This is the Group's first annual report and, in order to support the assessment, the Committee reviewed the principal risks, business model, financial review and KPIs to ensure these were representative of the business and consistent throughout the report and that areas requiring significant judgement and explanation have due prominence.

The Committee believes that the disclosures set out in the annual report provide the information necessary for shareholders to assess the Group's position, performance, business model and strategic outlook.

Internal controls and risk management

The Audit and Risk Committee is responsible for the oversight of the Group's system of internal controls, including the risk management framework and the work of the internal audit function. Details of the risk management framework are discussed within the risk management section on pages 47–48. The Group's principal risks and uncertainties, which provide a framework for the committee's focus, are discussed on pages 49–52. Management has identified the key operational and financial processes which exist within the business and has developed an internal control framework. This is structured around a number of Group policies and procedures and includes a delegated authority framework.

Internal auditors

The Audit and Risk Committee is responsible for the review and approval of the role and mandate of Internal Audit, including the approval of the annual internal audit plan and monitoring the effectiveness of Internal Audit.

PwC LLP was appointed in January 2018 for a term of three years as the Group's outsourced internal audit function ('Internal Audit') following a tender process. Its key objectives are to provide independent and objective assurance on risks and controls, to the Board, the Audit and Risk Committee and senior management, and to assist the Board in meeting its corporate governance responsibilities. The long term Internal Audit plan for 2018, 2019 and 2020 was approved by the Audit and Risk Committee in April 2018, as well as a short term Internal Audit plan for 2018. Going forward, the plans will be reviewed annually. The committee's chair has established a positive and effective working relationship with Internal Audit.

In its annual assessment of the effectiveness of Internal Audit, the Audit and Risk Committee will:

- Meet with Internal Audit without the presence of management to discuss the effectiveness of the function
- Review and re-assess the internal audit work plan; and
- Monitor and assess the role and effectiveness of Internal Audit in the overall context of the Group's risk management.

External auditors

Ernst and Young LLP ('EY' and the 'External Auditor') were appointed as auditors in 2018 and undertook their first audit for the year ended 31 December 2017. Energean Oil and Gas plc became a Public Interest Entity in 2018 on admission to trading on the London Stock Exchange. The Company has to comply with the EU Audit Directive (2014/56/EU) and Audit Regulation (537/2014) and will be required to put the external audit contract out to tender by 2028. The current lead audit partner is Andrew Smyth.

The External Auditor will attend each meeting of the Audit and Risk Committee and will report on their audit work and conclusions including the appropriateness of the judgements made by management and their compliance with International Financial Reporting Standards.

The Audit and Risk Committee has responsibility for the oversight of the external audit plan. This includes monitoring the independence and objectivity of EY, the quality of the audit services and their effectiveness, the level of fees paid, approval of non-audit services provided by EY and re-appointment.

The committee concluded that EY are objective, and operate at a high standard and will be recommending to the Board that the External Auditor be re-appointed at this year's AGM for the financial year ending 31 December 2018.

Non-audit services

In order to safeguard the auditor's independence and objectivity, the Group has in place a policy setting out the circumstances in which the auditor may be engaged to provide services other than those covered by the Group audit. The policy complies with the FRC's Ethical Standard for Auditors, published in September 2015, which implemented the EU's revised Statutory Audit Directive.

The Policy sets out those types of services that are strictly prohibited and those that are allowable in principle (permissible services). Any service types that do not fall within either list are considered by the Audit and Risk Committee Chairman on a case by case basis, supported by a risk assessment prepared by management.

No fees were paid during 2017 to EY, for audit or non-audit services.

Whistleblowing policy

The Group has a Whistleblowing policy in place and the committee is responsible for overseeing the arrangements and the effectiveness of the processes. The policy exists to enable employees to raise concerns in confidence about wrongdoing or impropriety within the Group.

Performance of the committee

The performance of the Audit and Risk Committee will be assessed by way of an internal process in 2018.

Our priorities for 2018

Looking forward to 2018, the committee will focus on monitoring the implementation of the short term Internal Audit plan for 2018 and it will review this towards the end of 2018.

Andrew Bartlett
Audit and Risk Committee Chairman
30 April 2018

[1] Founders means Oilco Investments Limited, Growthy Holdings Co. Limited and Adobelero Holdings Co. Limited

Nomination and governance committee report



It is my pleasure to introduce the Nomination and Governance Committee Report for 2017, which sets out the composition and role of the committee and the areas of focus for 2018.

Membership

The other members of the Nomination and Governance Committee are Andrew Bartlett and Efstathios Topouzoglou.

The Code recommends that a majority of the members of the Nomination and Governance Committee be Independent Non-Executive Directors and that the Chairman (other than where the committee is dealing with the appointment of a successor to the chairmanship) or an Independent Non-Executive Director should chair the committee. As I was considered to be independent upon appointment as Chairman and Andrew Bartlett is considered to be an Independent Non-Executive, we believe that the Company complies with the requirements of the Code in this respect.

Role of the committee

The Nomination and Governance Committee assists the Board in reviewing the structure, size and composition of the Board, including providing advice to the Board on the retirement and appointment of additional and/or replacement Directors. It is also responsible for reviewing succession plans for the Directors, including the Chairman and Chief Executive and other senior executives.

Meetings

The Nomination and Governance Committee became effective upon Admission in March 2018, therefore no meetings were held in 2017. The committee plans to meet once in 2018. Any member of the committee may however request a meeting if he/she considers that one is necessary or expedient.

Diversity

The committee's key area of responsibility is to ensure the composition of the Board is appropriate for oversight of the strategic direction of the Group and this includes reviewing the balance of skills and knowledge. The Nomination and Governance Committee is aware of the benefits of diversity in the boardroom and believes that a wide range of experience, backgrounds, perspectives and skills generates effective decision-making.

The Board will be establishing a board diversity policy in 2018 and we look forward to presenting the key principles of the new policy and how it has been implemented in the 2018 Annual Report.

Board effectiveness

As reported earlier on page 55, an evaluation of Board effectiveness will take place during 2018. The Company Secretary will facilitate an internal self-assessment of the Board and committees.

Performance of the committee

The performance of the Nomination and Governance Committee will be assessed by way of an internal process in 2018.

Our priorities for 2018

In 2018, the Nomination and Governance Committee will focus on succession planning to ensure the Group retains senior executives with the necessary skills and knowledge to remain effective and the committee will work alongside the Board to prepare and implement the board diversity policy.

Simon Heale
Nomination and Governance Committee Chairman
30 April 2018

Health, safety and environment committee report



As Chairman of the Health, Safety and Environment Committee, it is my responsibility to ensure that the committee is rigorous and effective in carrying out its role.

Membership

The other members of the Health, Safety and Environment Committee are Karen Simon and Ohad Marani.

Role of the committee

The Health, Safety and Environment Committee evaluates the effectiveness of the Group's policies and systems for identifying and managing environmental, health, safety and security risks as well as matters relating to equality, diversity, business ethics and corporate social responsibility. Additionally, the committee assesses the performance of the Group with regard to the impact of decisions and related actions in these areas upon employees, communities and other third parties, as well as upon the reputation of the Group.

Meetings

The Health, Safety and Environment Committee became effective upon Admission in March 2018, therefore no meetings were held in 2017. The committee plans to meet once in 2018. Any member of the committee may however request a meeting if he/she considers that one is necessary or expedient. .

Performance of the committee

The performance of the Health, Safety and Environment Committee will be assessed by way of an internal process in 2018.

Our priorities for 2018

In 2018, the Health, Safety and Environment Committee will focus on reviewing the effectiveness of the Group's policies and systems for identifying the risk of major accidents and conduct assurance of the key health, safety and environmental controls designed to prevent occurrence of accidents. The committee also expects to review the Group's plans for an enhanced Corporate Social Responsibility (CSR) strategy.

Robert Peck
Health, Safety and Environment Committee Chairman
30 April 2018

Remuneration report



I am pleased to present the Remuneration Committee Report which sets out the executive remuneration policy.

The Company was only recently admitted to the main market of the London Stock Exchange, on 21 March 2018. Consequently, as the Company was not listed during 2017, the Companies Act does not require the production of a Remuneration Report in respect of 2017. However, in the interests of transparency, the Board has decided that it would be appropriate to include a form of Remuneration Report in this Annual Report in order to outline the remuneration structure for 2018.

Membership of the Remuneration Committee

The other members of the Remuneration Committee are Andrew Bartlett, David Bonanno and Robert Peck.

Role of the Remuneration Committee

The Remuneration Committee's primary role is to determine and agree with the Board the executive remuneration policy and approve individual remuneration arrangements for the Chairman and Executive Directors with the objective of ensuring that the levels of remuneration are sufficient to promote the long-term success of the Company.

Remuneration strategy

The Company's remuneration strategy is to provide pay packages that will:

- motivate and retain industry leading employees;
- attract high quality individuals to join the Company;
- encourage and support a high performance culture;
- reward delivery of the Company's business plan and key strategic goals; and
- align employees with the interests of shareholders and other external stakeholders.

Executive Directors' remuneration

Consistent with the remuneration strategy, the Remuneration Committee has agreed a remuneration policy for the Executive Directors, whereby:

- salaries are set at competitive, but not excessive, levels compared to peers and other companies of an equivalent size and complexity;
- performance-related pay, based on stretching targets, forms a significant part of remuneration packages; and
- there is an appropriate balance between rewards for delivery of short-term and longer-term performance targets.

The remuneration framework intended to deliver this policy for the Executive Directors will be a combination of base salary, benefits, annual and deferred bonuses and awards under the Long-Term Incentive Plan (LTIP).

Due to the provisions of the City Code on Takeovers and Mergers as regards shareholders who may act in concert with each other, it is currently intended that the Executive Directors' deferred bonus and LTIP awards will be granted as phantom share awards to be settled in cash. As and when those provisions are no longer applicable, a more standard equity settlement approach will be adopted.

Executive Directors' remuneration will usually be reviewed annually and assessed taking into account the scope and requirements of the role, experience of the individual and the total remuneration package. Account will also be taken of remuneration arrangements in peer companies and the wider employee group.

Remuneration arrangements for 2018 are summarised below.

	2018 base salary
Mathios Rigas (Chief Executive Officer)	£675,000
Panos Benos (Chief Financial Officer)	£450,000

Benefits

Mathios Rigas receives a benefits package worth £75,000 per annum and Panos Benos receives a benefits package worth £50,000 per annum.

Annual bonus

Consistent with best practice for UK listed companies, a cap has been introduced on the maximum annual bonus opportunity. In 2018 the Executive Directors will be able to earn a bonus up to a maximum of 150% of base salary. At least one-third of any bonus earned by the Executive Directors in 2018 will be deferred for two years.

Bonuses in 2018 will be determined by a combination of financial, strategic and operational Company measures and performance measures appropriate to the individual Executive Director's role. These measures are currently commercially sensitive. However, retrospective disclosure will be provided in the next Remuneration Report to the extent that they do not remain commercially sensitive at that time.

Malus and clawback provisions may be applied to a bonus up to three years from the determination of the bonus.

LTIP

An LTIP award will be granted to the Executive Directors during 2018 worth (at grant) 200% of salary. Performance conditions for this award will be determined by the Remuneration Committee at the time of grant and will be disclosed in the next Remuneration Report. At least 50% of this award will be based on relative Total Shareholder Return.

The LTIP award granted to the Executive Directors in 2018 will be subject to a three year performance period and two year holding period.

Malus and clawback provisions may be applied to LTIP awards up to the fifth anniversary of grant.

Shareholding guideline

Executive Directors are subject to share ownership guidelines that require them to build up and retain a shareholding worth 200% of their base salary. Until an Executive Director has satisfied their guideline, they are required to retain at least 50% of vested share awards (after selling sufficient shares to satisfy any tax liabilities upon vesting).

Notice period

The Company, or the relevant Executive Director, may terminate the appointment of that Executive Director at any time upon six months' written notice.

Non-Executive Directors

Non-Executive Directors receive a basic fee plus supplementary fees for roles with additional time commitment. The fee structure that has applied since Admission is summarised below.

	Annual fee
Company Chairman	£150,000
Basic Non-Executive Director fee	£50,000
Supplementary fees	
▶ Audit Committee Chairman	£5,000
▶ Remuneration Committee Chairman	£5,000
▶ Health, Safety and Environment Committee Chairman	£5,000
▶ Senior Independent Director	£7,500

Fees may be paid in cash and / or shares. In addition, the Non-Executive Directors are reimbursed for expenses that are reasonably required for the performance of their duties.

The Company, or the relevant Non-Executive Director, may terminate the appointment of that Non-Executive Director at any time upon three months' written notice.

No fee is paid to David Bonanno who is employed and remunerated by Third Point.

2019 Annual General Meeting

The Company will be required to submit a remuneration policy (as it relates to the Directors) to a binding shareholder vote at the 2019 Annual General Meeting.

Accordingly, the Company will outline its future policy relating to the Directors' remuneration in its Report and Accounts for its financial year ending 31 December 2018.

On behalf of the Board

Ohad Marani
Remuneration Committee Chairman
30 April 2018

Directors' report

The Directors present their annual report on the affairs of the Group, together with the financial statements and auditor's report, for the year ended 31 December 2017. The Corporate Governance Statement set out on pages 55–67 forms part of this report.

Details of significant events since the balance sheet date are contained in note 38 to the financial statements. An indication of likely future developments in the business of the Company and details of research and development activities are included in the strategic report.

Admission to the Main Market of the London Stock Exchange

On 21 March 2018, all of the Company's issued ordinary shares were admitted to trading on the main market for listed securities of the London Stock Exchange.

Dividends

No dividends were paid during the year 2017.

Capital structure

Details of the issued share capital are shown in note 14 to the Financial Statements. Following Admission, the Company's share capital consisted of 152,823,238 issued ordinary shares of £0.01 each. The Company has one class of ordinary shares which carry no right to fixed income. Each share carries the right to one vote at general meetings of the Company. No person has any special rights of control over the Company's share capital and all issued shares are fully paid.

There are no specific restrictions on the size of a holding nor on the transfer of shares, which are both governed by the general provisions of the Articles of Association and prevailing legislation. The Directors are not aware of any agreements between holders of the Company's shares that may result in restrictions on the transfer of securities or on voting rights.

As at 31 December 2017, the Group did not have any employee share scheme in place.

With regard to the appointment and replacement of Directors, the Company is governed by its Articles of Association, the UK Corporate Governance Code, the Companies Act and related legislation. The Articles themselves may be amended by special resolution of the shareholders. The powers of directors are described in the Articles of Association and the Schedule of Matters Reserved for the Board, copies of which are available on request, and the Corporate Governance Statement on page 60.

The authority to issue shares in the Company may only be granted by the Company's shareholders and once granted such authority shall be exercised by the Directors.

There are a number of agreements entered into by members of the Group that take effect, alter or terminate upon a change of control of the Company, such as commercial contracts and bank loan agreements. None of these are considered to be significant in terms of their likely impact on the business of the Group as a whole. Furthermore, the Directors are not aware of any agreements between the Company and its Directors or employees that provide for compensation for loss of office or employment that occurs because of a takeover bid.

Directors

The biographical details and appointments of the Directors are set out on pages 56–59. All of the Directors will offer themselves for election or re-election at the AGM on 28 June 2018.

All of the current Directors served from incorporation of the Company on 8 May 2017, except as noted below:

- Simon Heale (Non-Executive Chairman) (appointed 11 July 2017)
- Andrew Bartlett (Senior Independent Director) (appointed 22 August 2017)
- Robert Peck (Independent Non-Executive Director) (appointed 11 July 2017)
- Ohad Marani (Independent Non-Executive Director) (appointed 11 July 2017)
- Karen Simon (Independent Non-Executive Director) (appointed 15 September 2017)

Note that Mr Scott Leslie was appointed 8 May 2017 and resigned 22 August 2017.

Directors' interests

The interests of the Directors in the Ordinary Shares of the Company are shown below:

Director	Number of shares as at publication of this Annual Report and Accounts 2017
Mathios Rigas	19,437,816[1]
Panos Benos	4,055,713[2]
Simon Heale	52,478[3]
Andrew Bartlett	2,126
Efstathios Topouzoglou	17,819,893[4]
Robert Peck	2,690
Ohad Marani	2,690
Karen Simon	89,949
David Bonanno	0[5]

1 The shares are held by Mathios Rigas, Growthy Holdings Co. Limited and Capital Energy Investments Limited, each of which is beneficially owned and controlled by Mathios Rigas.
2 The shares are held by Adobelero Holdings Co. Limited, beneficially owned and controlled by Panos Benos.
3 Mrs. C.J. Heale, wife of Simon Heale, holds 10,500 of the shares set out here and Simon Heale holds the balance, being 41,978 shares.
4 The shares are held by Efstathios Topouzoglou, Oilco Investments Limited and HIL Hydrocarbon Investments Limited, each of which is beneficially owned and controlled by Efstathios Topouzoglou.
5 David Bonanno is an employee of Third Point LLC, which manages its investment in the Company through Third Point Hellenic Recovery Fund L.P., the parent company of Third Point Hellenic Recovery (Lux) S.À.R.L, a substantial shareholder of the Company.

Directors' indemnities

Under the Company's Articles, the Directors of the Company may be indemnified out of the assets of the Company against certain liabilities which may be incurred in relation to the affairs of the Company or in relation to the duties, powers and office of each Director. Such qualifying third party indemnity provisions for the benefit of the Directors were implemented upon incorporation of the Company on 8 May 2017 and remain in force at the date of this report.

Political contributions

No political donations were made during the year.

Substantial shareholdings

Following Admission on 21 March 2018 and up to 26 April 2018, the Company has been notified in accordance with Chapter 5 of the Disclosure Guidance and Transparency Rules (or otherwise) of the following holdings in the Company's issued share capital:

	Number of shares	% of issued share capital
Third Point Hellenic Recovery (Lux) S.Á.R.L.	40,782,418	**26.7%**
Growthy Holdings Co. Limited	18,661,564	**12.2%**
Oilco Investments Limited	17,053,253	**11.2%**
Clal Insurance	15,780,878	**10.3%**
The Capital Group Companies, Inc.	10,874,957	**7.1%**
Pelham Capital	7,251,942	**4.7%**
Kerogen Investments No. 9 Limited	5,523,308	**3.6%**

Annual General Meeting ('AGM')

The Company's AGM will be held in London on 28 June 2018. Formal notice of the AGM will be issued separately from this Annual Report and Accounts.

Registrars

The Company's share registrar in respect of its ordinary shares traded on the London Stock Exchange is Computershare Investor Services PLC, full details of whom can be found in the Company Information section on page 156.

Greenhouse gas emissions (GHG) reporting

Following Admission on 21 March 2018, the Company intends to provide GHG emissions data for the period 1 January 2018 to 31 December 2018 in the Annual Report and Accounts 2018.

Directors' statement of disclosure of information to auditor

Each of the Directors in office at the date of the approval of this Directors' Report have confirmed that so far as such Director is aware, there is no relevant audit information (as defined in Section 418 of the Companies Act 2006) of which the Company's auditor is unaware; and such Director has taken all the steps that he/she ought to have taken as a director in order to make himself/herself aware of any relevant audit information and to establish that the Company's auditor is aware of that information. This confirmation is given and should be interpreted in accordance with the provisions of Section 418 of the Companies Act 2006.

Directors' report
continued

Independent auditor

Having reviewed the independence and effectiveness of the auditor, the Audit & Risk Committee has recommended to the Board that the existing auditor, Ernst & Young LLP ('EY'), be reappointed. EY have expressed their willingness to continue in office as auditor. An ordinary resolution to reappoint EY as auditor of the Company will be proposed at the forthcoming AGM.

Requirements of the Listing Rules

The following table provides references to where the information required by Listing Rule 9.8.4R is disclosed.

Listing Rule requirement	Listing Rule Reference	Section
Capitalisation of interest	LR 9.8.4R (1)	Note 28/page 129
Publication of unaudited financial information	LR 9.2.4R (2)	Not applicable
Long-term incentive schemes	LR 9.2.4R (4)	Directors' remuneration report/ pages 66–67
Director emoluments	LR 9.2.4R (5), (6)	No such waivers. David Bonanno does not receive any fee for acting as a Director.
Allotment of equity securities	LR 9.2.4R (7), (8)	No such share allotments.
Listed shares of a subsidiary	LR 9.2.4R (9)	Not applicable
Significant contracts with Directors and controlling shareholders	LR 9.2.4R (10), (11)	Directors' report/pages 68–70
Dividend waiver	LR 9.2.4R (12), (13)	Not applicable
Board statement in respect of relationship agreement with the controlling shareholder	LR 9.2.4R (14)	Not applicable

The Directors' Report was approved by the Board and signed on its behalf by the Company Secretary on 30 April 2018.

21 Gloucester Place
London
W1U 8HR

By order of the Board

Michelle Churchward
Company Secretary
30 April 2018

Statement of Directors' responsibilities for the Group financial statements

The Directors of the Company are responsible for preparing the Annual Report and the financial statements in accordance with applicable law and regulations.

Company law requires the Directors to prepare such financial statements for each financial year. Under that law, the Directors are required to prepare Group financial statements in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union and Article 4 of the IAS Regulation and have also chosen to prepare the parent company financial statements in accordance with Financial Reporting Standard 101 Reduced Disclosure Framework. Under company law, the Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of the Company and of the profit or loss of the Company for that period.

In preparing the parent company financial statements, the Directors are required to:

- select suitable accounting policies and then apply them consistently;
- make judgements and accounting estimates that are reasonable and prudent;
- state whether Financial Reporting Standard 101 Reduced Disclosure Framework has been followed, subject to any material departures disclosed and explained in the financial statements; and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the parent company will continue in business.

In preparing the Group financial statements, International Accounting Standard 1 requires that the Directors:

- properly select and apply accounting policies;
- present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information;
- provide additional disclosures when compliance with the specific requirements in IFRSs are insufficient to enable users to understand the impact of particular transactions, other events and conditions on the entity's financial position and financial performance; and
- make an assessment of the Group's ability to continue as a going concern.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the Company's transactions and disclose with reasonable accuracy at any time the financial position of the Company and enable them to ensure that the financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The Directors are responsible for the maintenance and integrity of the corporate and financial information included on the Company's website. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Responsibility statement

We confirm that to the best of our knowledge:

- the financial statements, prepared in accordance with the relevant financial reporting framework, give a true and fair view of the assets, liabilities, financial position and profit or loss of the company and the undertakings included in the consolidation taken as a whole;
- the strategic report includes a fair review of the development and performance of the business and the position of the Company and the undertakings included in the consolidation taken as a whole, together with a description of the principal risks and uncertainties that they face; and
- the annual report and financial statements, taken as a whole, are fair, balanced and understandable and provide the information necessary for shareholders to assess the Company's position and performance, business model and strategy.

This responsibility statement was approved by the board of directors on 30 April 2018 and is signed on its behalf.

By order of the Board

Mathios Rigas
Chief ExecutiveOfficer
30 April 2018

Panos Benos
Chief Financial Officer
30 April 2018

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Independent auditor's report to the members of Energean Oil & Gas Plc

Opinion

In our opinion:

- Energean Oil & Gas plc's group financial statements and parent company financial statements (the 'financial statements') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2017, of the group's profit for the year then ended, and of the parent company's profit for the period then ended;
- the group financial statements have been properly prepared in accordance with International Financial Reporting Standards ('IFRSs') as adopted by the European Union;
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006, and, as regards to the group financial statements, Article 4 of the IAS Regulation.

We have audited the financial statements of Energean Oil & Gas plc (Energean) that comprise:

Group	Parent
Consolidated statement of financial position as at 31 December 2017	Company statement of financial position as at 31 December 2017
Consolidated statement of profit or loss for the year then ended	Company statement of profit or loss and other comprehensive income for the period then ended
Consolidated statement of comprehensive income for the year then ended	
Consolidated statement of changes in equity for the year then ended	Company statement of changes in equity for the period then ended
Consolidated statement of cash flows for the year then ended	
Related notes 1 to 38 to the group financial statements, including a summary of significant accounting policies	Company accounting policies and the related notes 1 to 9 to the company financial statements

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and IFRSs as adopted by the European Union. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including Financial Reporting Standard 101 Reduced Disclosure Framework (United Kingdom Generally Accepted Accounting Practice).

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the financial statements section of our report below.

We are independent of the group and parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the FRC's Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Conclusions relating to principal risks, going concern and viability statement

We have nothing to report in respect of the following information in the annual report, in relation to which the ISAs (UK) require us to report to you whether we have anything material to add or draw attention to:

- the disclosures in the annual report set out on pages 49–52 that describe the principal risks and explain how they are being managed or mitigated;
- the directors' confirmation set out on page 49 in the annual report that they have carried out a robust assessment of the principal risks facing the entity, including those that would threaten its business model, future performance, solvency or liquidity;
- the directors' statement set out on page 35 in the Financial Review section about whether they considered it appropriate to adopt the going concern basis of accounting in preparing them, and their identification of any material uncertainties to the entity's ability to continue to do so over a period of at least twelve months from the date of approval of the financial statements;
- whether the directors' statement in relation to going concern required under the Listing Rules in accordance with Listing Rule 9.8.6R(3) is materially inconsistent with our knowledge obtained in the audit; or
- the directors' explanation set out on page 53 in the annual report as to how they have assessed the prospects of the entity, over what period they have done so and why they consider that period to be appropriate, and their statement as to whether they have a reasonable expectation that the entity will be able to continue in operation and meet its liabilities as they fall due over the period of their assessment, including any related disclosures drawing attention to any necessary qualifications or assumptions.

Auditor's report
continued

Overview of our audit approach	
Key audit matters	▶ Recoverability of oil and gas assets, including estimation of oil and gas reserve volumes; ▶ Assessment of impairment indicators within exploration and evaluation intangible assets; and ▶ Impact of the Energean Israel reorganisation.
Audit scope	▶ We performed an audit of the complete financial information of three components and audit procedures on specific balances for a further four components. ▶ The components where we performed full or specific audit procedures accounted for 99% of profit before tax, 99% of revenue and 99% of total assets.
Materiality	▶ Overall group materiality of $1.9 million which represents 0.5% of Total Assets, adjusted to remove the derivative financial asset connected with the Energean Israel Reorganisation.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. These matters included those which had the greatest effect on: the overall audit strategy, the allocation of resources in the audit; and directing the efforts of the engagement team. We communicated key audit matters and our planned response to each risk to the Audit and Risk Committee in our March audit planning report. These matters were addressed in the context of our audit of the financial statements as a whole, and in our opinion thereon, and we do not provide a separate opinion on these matters.

Risk	Our response to the risk	Key observations communicated to the Audit and Risk Committee
Recoverability of oil and gas assets, including estimation of oil and gas reserve volumes Tangible oil and gas properties: $248.9 million (2016: $179.4 million) *Refer to the Audit and Risk Committee Report (pages 62-63); Accounting policies; and Notes 3.5, 3.7, 4.2, 6 and 22 of the Consolidated Financial Statements (pages 90-126)* This refers to the risk that capitalised costs associated to tangible oil and gas assets may be recorded at a level that exceeds future recoverable value. In the Energean group, we consider this risk to exist predominantly for the established assets in Greece. Accounting standards require management to assess at each reporting date whether indicators of asset impairment exist. Where indicators of impairment (or reversal) exist, management must carry out an impairment test. Management prepare their tangible asset impairment tests under the value-in-use methodology. The models include a number of accounting estimates and judgements performed by management including: reserve and resources volume estimates, future oil and gas prices, discount rates, production forecasts and operating and capital expenditures for each cash generating unit (CGU). Changes to one or more of these key inputs could lead to a potential impairment or a reversal of impairment.	Procedures to evaluate management's assessment of impairment indicators, in accordance with the requirements of IAS 36, for the tangible oil and gas assets in Greece, included: ▶ Assessing the completeness of management's third party reserves and resources report, as well as the objectivity and competency of the report authors, and verifying input data used within the report; ▶ Inspecting management's reconciliation of the third party reserves and resources report with Energean's valuation model to assess economic cut off; ▶ The use of EY valuation specialists to assist the audit team in assessing the reasonableness of other key accounting estimates and judgements prepared by management, as well as the valuation methodology used by Energean management in the valuation model; ▶ Reperforming calculations in management's valuation model to ensure there is a sufficient headroom over the carrying value of the oil and gas assets; and ▶ Challenging the reasonableness of future production assumptions used in management's valuation model.	We reported to the Audit and Risk Committee in the April 2018 meeting that: ▶ With respect to the developed producing and the undeveloped tangible assets, we did not identify any further impairment indicators that gave rise to issues with recoverable value; and ▶ Management's estimates of reserves and resources, as well as key assumptions used in the valuation model, were found to be reasonable.

Risk	Our response to the risk	Key observations communicated to the Audit and Risk Committee
Assessment of impairment indicators for exploration and evaluation intangible assets Impairment charge: $6.7 million (2016: $0.0 million) Intangible exploration and evaluation ('E&E') assets: $3.4 million (2016: $7.7 million) *Refer to the Audit and Risk Committee Report (pages 62-63); Accounting policies; and Notes 3.7, 7 and 22 of the Consolidated Financial Statements (pages 90-126)* The Group's E&E assets need to be considered for impairment in each reporting period in line with the requirements of IFRS 6 *Exploration for and Evaluation of Mineral Resources* ('IFRS 6'). The recoverability of capitalised costs will depend upon internal and external factors, including the terms of the exploration rights and allocation of future capital by management, as well as technical and economic prospects which could pose a risk to the ability to progress intangible assets to the development stage. A lack of consideration of the above factors could lead to inappropriate valuation of the assets in the financial statements.	Our response was led by the Group audit team, with significant input from our two component audit teams responsible for two full scope components. For exploration costs held as intangible assets relating to future oil and gas prospects, our procedures included: ▶ Verifying remaining exploration periods, rights and associated costs capitalised under licence agreements; and ▶ Evaluating management's identification and assessment of future development potential and whether the impairment recognised is appropriate and in line with IFRS 6.	We reported to the Audit and Risk Committee in the April 2018 meeting that: ▶ With respect to capitalised exploration costs held at the balance sheet date, we did not identify any further indicators of impairment in the remaining intangible assets; and ▶ The calculated impairment charge of $1.2 million was considered to be appropriate.
Impact of the Energean Israel reorganisation Derivative asset: $93.3 million. Investment in Joint Ventures: $0.0 million (2016: $0.0 million). *Refer to the Audit and Risk Committee Report (page 62-63); Accounting policies; and Notes 4.2, 9, 31.4, 34.2 and 38 of the Consolidated Financial Statements (pages 103-140); and Note 4 of the Company financial statements (page 147).* During 2017 and in the post balance sheet period, Energean's interests in Energean Israel Limited have been subject to several structural changes. At 31 December 2017, the Energean group held certain voting rights over Energean Israel Limited but held no rights to the economic interests. During 2017, the Group entered into several contractual agreements concerning the ownership of Energean Israel Limited. At 31 December 2017, the Energean group held a commitment to acquire 70% of preference shares in Energean Israel Limited from the Energean founders (50%) and from Kerogen Investments No.38 Limited (20%), This commitment related to the post balance sheet period and would crystallise upon a successful Initial Public Offering ('IPO') or in the event of a sale transaction. Management has recognised a derivative financial instrument in the 2017 financial statements ($93.3m derivative asset), using an estimate as at 31 December 2017 of the likelihood of the IPO process being successful and the exercise price related to the commitment. There exists a risk that this arrangement, or the Group's financial interests in Energean Israel Limited, are inappropriately accounted for and/or materially misstated within the financial statements, due to the complexity of the reorganisation agreements and their significance to the Group.	The accounting for the commitment to purchase 70% of share capital in Energean Israel Limited (which management identified as a derivative asset at 31 December 2017) and the related valuation judgements were considered within our audit approach. Our procedures focused on understanding the terms of the restructuring agreements entered into during 2017 and the contractual commitments that the Energean Group was bound by as a result of such agreements, together with the related accounting implications. We inspected management's approach to value the derivative financial asset, which is based on the estimated difference between the consideration payable under the relevant agreement and the estimated value of the B shares in Energean Israel Limited that were to be acquired, and independently performed recalculations based on management's model. The transaction prices within management's valuation model were agreed to the contractual agreements entered into by Energean. We focused on the key assumptions used by management to determine the fair value of the derivative financial asset, including the probability of the IPO being successful as at 31 December 2017 (50%). We performed subsequent events procedures in relation to the acquisition of the 50% of the preference shares in Energean Israel from the Energean founding shareholders and an additional 20% of Energean Israel shares from Kerogen Investments No.38 Limited, which completed prior to the approval of the 2017 Annual Report and Accounts. We considered the adequacy of the disclosures regarding this reorganisation in the financial statements of the Energean group.	We reported to the Audit and Risk Committee in the April 2018 meeting that: ▶ We concluded that it is appropriate to recognise a derivative financial asset in respect of the Energean Israel Reorganisation; ▶ Management's estimation of the derivative financial asset valuation and corresponding profit recognised within the year was materially reasonable; and ▶ Disclosure of the Energean Israel Reorganisation and the impact of the post balance sheet event relating to the Energean Israel reorganisation within the financial statements was considered appropriate.

Auditor's report
continued

Revenue recognition is a significant risk presumed by ISAs (UK). It is not included above, as Energean's revenue streams are largely routine in nature and do not involve significant judgement or use of significant estimates. Consequently, the auditing of revenue recognition did not have the greatest effect on our overall audit strategy, the allocation of resources in the audit or in directing the efforts of the engagement team.

An overview of the scope of our audit

Tailoring the scope

Our assessment of audit risk, our evaluation of materiality and our allocation of performance materiality determine our audit scope for each entity within the group. Taken together, this enables us to form an opinion on the consolidated financial statements. We take into account size, risk profile, the organisation of the group and effectiveness of group-wide controls, and changes in the business environment when assessing the level of work to be performed at each entity.

In assessing the risk of material misstatement to the group financial statements, and to ensure we had adequate quantitative coverage of significant accounts in the financial statements, of the ten reporting components of the group, we selected all ten components covering entities within Greece, Cyprus, Egypt, Montenegro, Israel and the United Kingdom, which represent the principal business units within the group.

Of the ten components selected, we performed an audit of the complete financial information of three components ('full scope components') which were selected based on their size or risk characteristics. For the remaining seven components, we performed audit procedures on specific accounts within four components ('specific scope components') that we considered had the potential for the greatest impact on the significant accounts in the financial statements either because of the size of these accounts or their risk profile. The audit scope of these components may not have included testing of all significant accounts of the component but will have contributed to the coverage of the group tested.

The reporting components where we performed full scope and specific scope audit procedures accounted for 99% of the group's profit before tax, 99% of revenue and 99% of total assets.

For the remaining 3 components, we performed other procedures including the following to respond to any potential risks of material misstatement of the consolidated financial statements:

- Inspected key documentation surrounding the post balance sheet events connected with the Energean Israel Reorganisation;
- Analytical review procedures on a legal entity basis;
- Tested consolidation journals, intercompany eliminations and foreign currency translation recalculations;
- Made inquiries of management about unusual transactions in these components; and
- Reviewed minutes of Board meetings held throughout the period.

Involvement with component teams

In establishing our overall approach to the group audit, we determined the type of work that needed to be undertaken at each of the components by us, as the group audit engagement team, or by component auditors from other EY global network firms operating under our instruction. For two full scope components where the work was performed by two EY component teams (Athens and Thessaloniki), we determined the appropriate level of involvement to enable us to determine that sufficient audit evidence had been obtained as a basis for our opinion on the group as a whole.

The group audit team interacted regularly with the EY component teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. The group audit team followed a programme of planned visits that was designed to ensure that the group audit team members visited the full scope component teams during the current year's audit cycle. These visits involved discussing the audit approach with the component team and any issues arising from their work, meeting with local management, and reviewing key audit working papers on risk areas. The group team interacted regularly with the component teams during various stages of the audit, reviewed key working papers and were responsible for the scope and direction of the audit process. This, together with the additional procedures performed at group level, gave us appropriate evidence for our opinion on the consolidated financial statements. We maintained continuous and open dialogue with our EY component teams in addition to holding formal meetings to ensure that we were fully aware of their progress and results of their procedures.

Our application of materiality

We apply the concept of materiality in planning and performing the audit, in evaluating the effect of identified misstatements on the audit and in forming our audit opinion.

Materiality

The magnitude of an omission or misstatement that, individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of the financial statements. Materiality provides a basis for determining the nature and extent of our audit procedures.

We determined materiality for the group to be $1.9 million, which is 0.5% of total assets as at 31 December 2017, adjusted to remove the derivative financial asset connected with the Energean Israel Reorganisation ($93.3m) as this was not considered part of the underlying business at the year end. We believe that adjusted total assets provides us with a suitable basis for setting materiality for immature emerging oil and gas exploration and production companies, providing a reliable measure to assess the size of the group's operations.

We determined materiality for the parent company to be $4,000, which is 1% of net assets.

During the course of our audit, we reassessed initial materiality and no changes were made.

Performance materiality

The application of materiality at the individual account or balance level. It is set at an amount to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds materiality.

On the basis of our risk assessments, together with our assessment of the group's overall control environment, our judgement was that performance materiality was 50% of our planning materiality, namely $950,000. We have set performance materiality at this percentage based on our assessment of likelihood of misstatements based on our understanding of the group as part of our planning procedures.

Audit work at component locations for the purpose of obtaining audit coverage over significant financial statement accounts is undertaken based on a percentage of total performance materiality. The performance materiality set for each component is based on the relative scale and risk of the component to the group as a whole and our assessment of the risk of misstatement at that component. In the current year, the range of performance materiality allocated to components was $200,000 to $800,000.

We determined performance materiality for the parent company to be $2,000, based on the same judgement made for the Group.

Reporting threshold

An amount below which identified misstatements are considered as being clearly trivial.

We agreed with the Audit and Risk Committee that we would report to them all uncorrected audit differences in excess of $95,000, which is set at 5% of planning materiality, as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds.

For the parent company, we agreed with the Audit & Risk Committee that we would report to them all uncorrected differences in excess of $200, based on the same judgement made for the Group.

We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in light of other relevant qualitative considerations in forming our opinion.

Other information

The other information comprises the information included in the annual report set out on pages 01-71 and 149-156, other than the financial statements and our auditor's report thereon. The directors are responsible for the other information.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

In this context, we also have nothing to report in regard to our responsibility to specifically address the following items in the other information and to report as uncorrected material misstatements of the other information where we conclude that those items meet the following conditions:

- **Fair, balanced and understandable,** set out on page 71 – the statement given by the directors that they consider the annual report and financial statements taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess the group's performance, business model and strategy, is materially inconsistent with our knowledge obtained in the audit; or
- **Audit and Risk Committee reporting,** set out on pages 62-63 – the section describing the work of the Audit and Risk Committee does not appropriately address matters communicated by us to the Audit and Risk Committee; or
- **Directors' statement of compliance with the UK Corporate Governance Code,** set out on page 60 – the parts of the directors' statement required under the Listing Rules relating to the company's compliance with the UK Corporate Governance Code containing provisions specified for review by the auditor in accordance with Listing Rule 9.8.10R(2) do not properly disclose a departure from a relevant provision of the UK Corporate Governance Code.

Auditor's report
continued

Opinions on other matters prescribed by the Companies Act 2006

In our opinion, based on the work undertaken in the course of the audit:

- the information given in the Strategic Report and the Directors' Report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the Strategic Report and the Directors' Report have been prepared in accordance with applicable legal requirements.

Matters on which we are required to report by exception

In the light of the knowledge and understanding of the group and the parent company and its environment obtained in the course of the audit, we have not identified material misstatements in the Strategic Report or the Directors' Report.

We have nothing to report in respect of the following matters in relation to which the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements to be audited are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Responsibilities of directors

As explained more fully in the Directors' responsibilities statement set out on page 71, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the group and parent company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the group or the parent company or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

Explanation as to what extent the audit was considered capable of detecting irregularities, including fraud

The objectives of our audit, in respect to fraud, are; to identify and assess the risks of material misstatement of the financial statements due to fraud; to obtain sufficient appropriate audit evidence regarding the assessed risks of material misstatement due to fraud, through designing and implementing appropriate responses; and to respond appropriately to fraud or suspected fraud identified during the audit. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

Our approach was as follows:

- We obtained an understanding of the legal and regulatory frameworks that are applicable to Energean and determined that the most significant are those that relate to the reporting framework (IFRSs, Companies Act 2006, the UK Corporate Governance Code and Listing Rules of the UK Listing Authority) and the relevant tax compliance regulations in the jurisdictions in which the group operates. In addition, we concluded that there are certain significant laws and regulations that may have an effect on the determination of the amounts and disclosures in the financial statements and laws and regulations relating to health and safety, employee matters, environmental and bribery and corruption practices.
- We understood how the group is complying with those frameworks by making enquiries of management and with those responsible for legal and compliance procedures. We designed audit procedures to identify non-compliance with such laws and regulations identified in the paragraph above, including corroborating our enquiries through our review of Board minutes, papers provided to the Audit and Risk Committee and correspondence received from regulatory bodies, and noted that there was no contradictory evidence.
- We assessed the susceptibility of Energean's consolidated financial statements to material misstatement, including how fraud might occur, focussing on opportunities for management to reflect bias in key accounting estimates. We have reported our findings in our key audit matters section of our report. We also incorporated data analytics and manual journal entry testing into our audit approach.
- Other procedures performed to address the risk of management override included evaluating the business rationale for significant unusual and one-off transactions, reviewing the minutes of the Board of Directors and Audit and Risk Committee, and including a level of unpredictability in our testing.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at https://www.frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

Other matters we are required to address

- We were appointed by the company on 21 February 2018 to audit the financial statements for the year ending 31 December 2017 and subsequent financial periods.
- The period of total uninterrupted engagement including previous renewals and reappointments is one year, covering the year ending 31 December 2017.
- The non-audit services prohibited by the FRC's Ethical Standard were not provided to the group or the parent company and we remain independent of the group and the parent company in conducting the audit.
- The audit opinion is consistent with the report of the Audit and Risk Committee.

Andrew Smyth
Senior statutory auditor
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
30 April 2018

1 The maintenance and integrity of the Energean Oil & Gas plc website is the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2 Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Consolidated statement of financial position

	Notes	As at 31 December 2017 (US$ 000)	2016 (US$ 000)
Assets			
Non-current assets			
Property-plant and equipment	6	**309,976**	230,180
Intangible assets	7	**4,000**	8,278
Other non-current assets		**591**	382
Deferred tax asset	16	**13,473**	20,678
Bank deposits	13	**1,899**	1,116
		329,939	260,634
Current assets			
Inventories	11	**9,529**	12,757
Trade and other receivables	12	**24,684**	13,739
Current tax assets		**–**	92
Cash and cash equivalents	13	**13,793**	11,861
Derivative asset	34	**93,292**	–
Assets classified as held for sale	9	**–**	45,203
		141,298	83,652
Total assets		**471,237**	344,286
Equity and liabilities			
Equity attributable to owners of the parent			
Share capital	14	**917**	14,904
Equity reserves		**62,323**	117,080
Merger reserves	14	**139,903**	–
Retained earnings		**(138,455)**	(148,407)
Equity attributable to equity holders of the parent		**64,688**	(16,423)
Non-controlling interests	10	**224,294**	303
Total equity		**288,982**	(16,120)
Non-current liabilities			
Borrowings	15	**78,831**	255,118
Deferred tax liabilities	16	**3,570**	2,989
Retirement benefit liabilities	18	**3,288**	2,425
Provisions	17	**5,688**	2,240
Other long-term liabilities	19	**2,544**	2,737
		93,921	265,509
Current liabilities			
Trade and other payables	19	**66,528**	29,082
Borrowings	15	**12,500**	21,130
Provisions	17	**9,306**	–
Liabilities directly associated with assets classified as held for sale	9	**–**	44,685
		88,334	94,897
Total liabilities		**182,255**	360,406
Total equity and liabilities		**471,237**	344,286

Notes 1 to 38 are an integral part of the financial statements. The consolidated financial statements of Energean Oil & Gas plc for the year ended 31 December 2017 were authorised for issue in accordance with a resolution of the Directors on 30 April 2018 and were signed on its behalf by:

Mathios Rigas
Chief Executive Officer

Panos Benos
Chief Financial Officer

Consolidated income statement

	Notes	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Revenue	20	**57,752**	39,724
Cost of sales	21	**(48,648)**	(40,551)
Gross profit/(loss)		**9,104**	(827)
Administration expenses	23	**(5,991)**	(4,134)
Selling and distribution expenses	24	**(445)**	(336)
Exploration and evaluation expenses	22	**(9,966)**	(1,133)
Other income	26	**1,789**	248
Other expenses	25	**(8,187)**	(4,688)
Operating loss		**(13,696)**	(10,870)
Finance income	28	**14**	327
Finance costs	28	**(22,940)**	(29,311)
Gain on derivative	34	**25,786**	–
Net foreign exchange gain/(loss)		**36,243**	(10,043)
Profit/(loss) from continuing operations before tax		**25,407**	(49,897)
Taxation (expense)/income	29	**(14,061)**	11,517
Profit/(loss) from continuing operations		**11,346**	(38,380)
Discontinued operations			
Profit/(loss) from discontinued operations	9	**(1,403)**	(229)
Profit/(loss) for the period		**9,943**	(38,609)
Attributable to:			
Owners of the parent		**9,952**	(38,608)
Non-controlling interests		**(9)**	(1)
		9,943	(38,609)
Profit/(loss) per ordinary share from continuing activities (cents per share)			
From continuing operations	30	**$0.16**	($0.54)
From total earnings	30	**$0.14**	($0.54)

Consolidated statement of comprehensive income

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Profit/(loss) for the period	**9,943**	(38,609)
Other comprehensive income:		
Items that will not be reclassified subsequently to profit or loss		
Remeasurement of defined benefit pension plan	**(258)**	(148)
Exchange difference on the translation of the parent to presentation currency	**–**	(2,587)
Income taxes on items that will not be reclassified to profit or loss	**74**	41
	(184)	(2,694)
Items that may be reclassified subsequently to profit or loss		
Exchange difference on the translation of foreign operations, tax effect nil	**(2,252)**	4,347
	(2,252)	4,347
Other comprehensive (loss)/income after tax	**(2,436)**	1,653
Total comprehensive income/(loss) for the period	**7,507**	(36,956)
Total comprehensive income/(loss) attributable to:		
Owners of the parent	**7,516**	(36,955)
Non-controlling interests	**(9)**	(1)
	7,507	(36,956)

Consolidated statement of changes in equity

	Share capital (US$ 000)	Share premium (US$ 000)	Other reserves (US$ 000)	Translation reserves (US$ 000)	Accumulated losses (US$ 000)	Total (US$ 000)	Non-controlling interests (US$ 000)	Total (US$ 000)
At 1 January 2016	**14,904**	**125,851**	**(226)**	**(10,935)**	**(109,799)**	**19,795**	**304**	**20,099**
Comprehensive loss								
Loss for the year	–	–	–	–	(38,608)	(38,608)	(1)	(38,609)
Exchange difference on the translation of foreign operations	–	–	–	4,347	–	4,347	–	4,347
Exchange difference on the translation of the parent to presentation currency	–	–	–	(2,587)	–	(2,587)	–	(2,587)
Remeasurement of defined benefit pension plan	–	–	(148)	–	–	(148)	–	(148)
Income taxes on other comprehensive income	–	–	41	–	–	41	–	41
Total comprehensive (loss)/income			**(107)**	**1,760**	**(38,608)**	**(36,955)**	**(1)**	**(36,956)**
Transactions with owners								
Option for conversion to share capital (Note 9.1)	–	–	737	–	–	737	–	737
	–	–	737	–	–	737	–	737
At 31 December 2016	**14,904**	**125,851**	**404**	**(9,175)**	**(148,407)**	**(16,423)**	**303**	**(16,120)**

	Share capital (US$ 000)	Share premium (US$ 000)	Other reserves (US$ 000)	Translation reserves (US$ 000)	Accumulated losses (US$ 000)	Merger reserves (US$ 000)	Total (US$ 000)	Non-controlling interests (US$ 000)	Total (US$ 000)
At 1 January 2017	**14,904**	**125,851**	**404**	**(9,175)**	**(148,407)**	**–**	**(16,423)**	**303**	**(16,120)**
Profit for the period	–	–	–		9,952	–	9,952	(9)	9,943
Exchange difference on the translation of foreign operations	–	–	–	(2,252)	–	–	(2,252)	–	(2,252)
Remeasurement of defined benefit pension plan	–	–	(258)	–	–	–	(258)	–	(258)
Income taxes on other comprehensive income	–	–	74	–	–	–	74	–	74
Total comprehensive income	**–**	**–**	**(184)**	**(2,252)**	**9,952**	**–**	**7,516**	**(9)**	**7,507**
Transactions with owners of the Company									
Issuance of shares	65	–	–	–	–	–	65	–	65
Group restructuring	(14,052)	(125,851)	–	–	–	139,903	–	–	–
Modification of derivative (Note 34.2)	–	–	67,506	–	–	–	67,506	–	67,506
Transaction with non-controlling interests (Note 10)	–	–	6,761	–	–	–	6,761	224,000	230,761
Transfer due to disposal of subsidiary (Note 9.1)	–	–	(737)	–	–	–	(737)		(737)
At 31 December 2017	**917**	**–**	**73,750**	**(11,427)**	**(138,455)**	**139,903**	**64,688**	**224,294**	**288,982**

Consolidated statement of cash flows

	Notes	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Operating activities			
Profit/(loss) before tax		**24,004**	(50,126)
Adjustments:			
Depreciation of property, plant and equipment	6	**17,808**	21,355
Amortisation of intangible assets	7	**200**	144
Loss from the sale of property, plant and equipment		**–**	1,577
Impairment loss on inventory		**–**	403
Impairment loss on property, plant and equipment	6	**1,433**	1,947
Impairment loss on intangible assets	7	**6,663**	–
Gain from disposal of subsidiary	26	**(1,540)**	–
Increase in provisions		**8,748**	738
Finance income	28	**(14)**	(327)
Finance costs	28	**22,940**	29,311
Gain from financial instruments	34	**(25,786)**	–
Net foreign exchange (loss)/gain		**(36,243)**	10,039
		18,124	15,061
Changes in working capital:			
Inventories		**4,985**	(4,952)
Trade and other receivables		**(10,958)**	(1,530)
Trade and other payables		**17,157**	6,314
Other non-current asset		**(210)**	416
Cash flows from operations		**29,097**	**15,309**
Tax paid		**–**	–
Payments in relation to provisions		**–**	(74)
Net cash from operating activities		**29,097**	**15,235**
Investing activities			
Payment for purchase of intangible assets		**(5,259)**	(44,745)
Payment for purchase of property, plant and equipment		**(48,744)**	(65,935)
Disposal of subsidiary, net of cash disposed		**(5,610)**	–
Acquisition of subsidiary, net of cash acquired	9	**–**	47
Payment for purchase of investments in joint ventures		**–**	(41)
Proceeds from disposal of property, plant and equipment	6	**–**	1,747
Proceeds from disposal of intangible assets	7	**1,000**	–
Interest received		**14**	83
Net cash used in investing activities		**(58,599)**	**(108,844)**
Financing activities			
Repayments of loans	15	**–**	(20,000)
Proceeds from new loans		**33,915**	127,312
Finance cost paid		**(4,019)**	(2,692)
Transaction costs		**(1,475)**	(1,564)
Net cash from financing activities		**28,421**	**103,056**

	Notes	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Net increase/(decrease) in cash and cash equivalents		**(1,081)**	9,447
Cash and cash equivalents:			
At beginning of the year		**17,586**	8,238
Effect of exchange rate fluctuations on cash and cash equivalents		**(813)**	(99)
At end of the period	13, 9	**15,692**	**17,586**
Current cash and cash equivalents		**13,793**	11,861
Non-current bank deposits		**1,899**	1,116
Current cash and cash equivalents held for sale		**–**	4,609
Cash and cash equivalents at end of the period		**15,692**	**17,586**

Supplemental cash flow information:

	Notes	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Non-cash investing and financing activities			
Settlement of loan for issuance of preference shares	10	**230,761**	–
Capitalisation of depreciation to oil & gas properties	6	**2,388**	7,014
Capitalised borrowing costs		**1,258**	3,992

Accounting policies

(Amounts in thousands US$ except for share and per share amounts, unless otherwise stated)

1. Incorporation and principal activities

1.1 Incorporation

Energean Oil & Gas plc (the 'Company') was incorporated in England & Wales on 8 May 2017 as a public company with limited liability, under the Companies Act 2006. On incorporation, the Company issued 50,000 ordinary shares of a nominal value of £1.00 per share. Its registered office is at 21 Gloucester Place, London W1U 8HR, United Kingdom. The Company and all subsidiaries controlled by the Company, are together referred to as 'the Group'.

On 30 June 2017, the Company reorganised the business and became the parent company of the Group through the acquisition of the full share capital of Energean E&P Holdings Limited in exchange for 65,643,120 £0.01 shares in the Company (the 'transaction'). This transaction, which resulted in Energean E&P Holdings Limited becoming a wholly-owned subsidiary of the Company and the Company becoming the new immediate holding company of Energean E&P Holdings Limited, constitutes a group reconstruction and a transaction between entities under common control. This transaction falls outside the scope of IFRS 3 'Business Combinations'. There is no other authoritative guidance for such situations under IFRS. In the absence of such authoritative guidance under IFRS, the transaction has been accounted for in these consolidated financial statements using the principles of merger accounting under Financial Reporting Standard 102, the Financial Reporting Standard applicable in the UK and the Republic of Ireland, which results in the net assets of Energean E&P Holdings Limited being recorded at carrying value and presented as if the Company and Energean E&P Holdings Limited had always been part of the same consolidated group. This policy, which does not conflict with International Financial Reporting Standards (IFRS), reflects the economic substance of the transaction. The effect of this transaction is reflected in the share capital of the Group on the date it became effective.

1.2 Principal activities

The Group has been established with the objective of exploration, production and commercialisation of crude oil and natural gas in Greece, Israel, North Africa and the wider Eastern Mediterranean. The Group's core assets as of 31 December 2017 comprise:

	Asset	Country	Group's working interest	Partner's working interest	Field phase
1.	Karish[1]	Israel	50%	50%	Development
2.	Tanin[1]	Israel	50%	50%	Development
3	Blocks 12, 21, 22, 23, 31	Israel	100%	N/A	Exploration
4.	Prinos	Greece	100%	N/A	Production
5.	Prinos North	Greece	100%	N/A	Production/undeveloped
6.	South Kavala	Greece	100%	N/A	Production
7.	Epsilon	Greece	100%	N/A	Undeveloped
8.	Prinos exploration area	Greece	100%	N/A	Exploration
9.	Katakolo	Greece	100%	N/A	Undeveloped
10.	Ioannina[2]	Greece	40%	60%	Exploration
11.	Aitoloakarnania[3]	Greece	40%	60%	Exploration
12.	West Kom Ombo	Egypt	60%	40% (Pan Pacific Petroleum)	Exploration
13.	Block 26	Montenegro	100%	N/A	Exploration
14.	Block 30	Montenegro	100%	N/A	Exploration

1 Energean Israel holds 50% interests in Karish and Tanin licences, Kerogen Capital held the remaining 50% (Note 9). At 31 December 2017 Energean Israel is an associate in which the Group has 0% economic interest.
2 In March 2017 the Group agreed to farm out a 60% working interest to Repsol (operator) in Ioannina block.
3 Subject to ratification of lease agreement by Greek Parliament.

The principal operations of the Group are in Greece, Israel, Montenegro and Egypt.

2. Basis of preparation

The consolidated financial statements have been prepared on the historical cost basis, except for the revaluation of certain financial instruments that are measured at revalued amounts or fair values at the end of each reporting period, as explained in the accounting policies below.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU).

The consolidated financial information is presented in US dollars and all values are rounded to the nearest thousand dollars except where otherwise indicated.

Going concern

The Directors have exercised significant judgement in assessing that the preparation of the consolidated financial statements on a going concern basis is appropriate. In making this assessment, the important factors considered, among others, include the current financial position and the profitability of the Group as well their expectations in relation to future business prospects, and future profitability and cash flows of the Group. Another important factor for determining that the going concern basis remains appropriate is the ability of raising necessary funding as and when needed. Subsequent to the balance sheet date, the Group successfully completed an IPO on the London Stock Exchange and raised $460 million in gross proceeds. Furthermore the Group's liquidity position has been significantly improved by the amendment of the Group's existing EBRD Senior Facility agreement signed on 30 January 2018, increasing available funds to US$180 million and the addition of a US$1.275 billion Senior Credit Facility agreement, which will be used to fund Karish and Tanin development costs. Accordingly, the Directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future, and consider it appropriate to adopt the going concern basis in preparing the consolidated financial statements.

3. Accounting policies

The principal accounting policies and measurement bases used in the preparation of the consolidated financial statements are set out below. These policies have been consistently applied to all periods presented in the consolidated financial statements unless otherwise stated.

3.1 Basis of consolidation

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (its subsidiaries) as detailed in Note 8. Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee
- Exposure, or rights, to variable returns from its involvement with the investee, and
- The ability to use its power over the investee to affect its returns

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

The results of subsidiaries acquired or disposed of during the year are included in the consolidated financial statements from the effective date of acquisition or up to the effective date of disposal, as appropriate.

Accounting policies
continued

3.1 Basis of consolidation *continued*

Profit or loss and each component of Other Comprehensive Income (OCI) are attributed to owners of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the Group. All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Group's equity therein. Non-controlling interests consist of the amount of those interests at the date of the original business combination and the non-controlling interests' share of changes in equity since the date of the combination.

Transactions with non-controlling interests that do not result in loss of control of a subsidiary are accounted for as transactions with the owners (i.e. as equity transactions). The difference between the fair value of any consideration and the resulting change in the non-controlling interests' share of the net assets of the subsidiary is recorded in equity.

3.2 Functional and presentation currency and foreign currency translation

▶ Functional and presentation currency

Items included in the consolidated financial statements of the Company and its subsidiaries are measured using the currency of the primary economic environment in which each entity operates ('the functional currency').

The functional currency of the Company is US dollars ('US$'). The US dollar is the currency that mainly influences sales prices and revenue estimates, and also highly affects its operations. The functional currencies of the Group's main subsidiaries are as follows: for Energean E&P Holdings Ltd, Energean Oil & Gas S.A., Kavala Oil SA and Energean Montenegro is Euro, for Energean International Limited and Energean Israel Limited is US$.

▶ Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss. Such monetary assets and liabilities are translated at year end foreign exchange rates. Non-monetary items denominated in a foreign currency are translated at the exchange rates prevailing at the date of the transaction and are not subsequently remeasured.

▶ Translation to presentation currency

For the purpose of presenting consolidated financial statements information, the assets and liabilities of the Group are expressed in US$. The Company and its subsidiaries' assets and liabilities are translated using exchange rates prevailing on the reporting date. Income and expense items are translated at the average exchange rates for the period, unless exchange rates fluctuated significantly during that period, in which case the exchange rates at the dates of the transactions are used. Exchange differences arising are recognised in other comprehensive income and accumulated in the Group's translation reserve. Such translation differences are reclassified to profit or loss in the period in which the foreign operation is disposed of.

3.3 Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration transferred in a business combination is measured at fair value, which is calculated as the sum of the acquisition-date fair values of the assets transferred by the Group, liabilities incurred by the Group to the former owners of the acquiree and equity interests issued by the Group in exchange for control of the acquiree. For each business combination the acquirer measures the non-controlling interest in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are recognised in the consolidated statement of profit or loss as incurred.

Where appropriate, the cost of acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified are accounted for in profit or loss. Contingent consideration classified as equity is not remeasured.

The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 *Business Combinations* (revised 2008) are recognised at their fair value at the acquisition date, except that:

- deferred tax assets or liabilities, and assets or liabilities related to employee benefit arrangements, are recognised and measured in accordance with IAS 12, 'Income Taxes' and IAS 19, 'Employee Benefits' respectively;
- liabilities or equity instruments related to share-based payment arrangements of the acquiree or share-based payment arrangements of the Group entered into to replace share-based payment arrangements of the acquiree are measured in accordance with IFRS 2 Share-Based Payment at the acquisition date; and
- non-current assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 'Non-current Assets Held for Sale and Discontinued Operations', are measured at fair value less costs to sell.

If the initial accounting for a business combination is incomplete by the end of the reporting year in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as at the acquisition date that, if known, would have affected the amounts recognised as at that date.

The measurement period is the year from the date of acquisition to the date the Group receives complete information about facts and circumstances that existed as at the acquisition date, and is subject to a maximum of one year.

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed. If, after reassessment, the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a bargain purchase gain.

3.4 Investments in joint ventures

A joint arrangement is one in which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operations

A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have the right to the assets and obligations for the liabilities relating to the arrangement. In relation to its interests in joint operations, the Group recognises its share of:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Share of the revenue from the sale of the output by the joint operation
- Expenses, including its share of any expenses incurred jointly

Accounting policies
continued

3.4 Investments in joint ventures *continued*

Joint venture

A joint venture is an arrangement (which usually involves the establishment of a separate entity) that the Group controls jointly with one or more other investors, and over which the Group has rights to a share of the net assets rather than direct rights to underlying assets and obligations for underlying liabilities.

The investments in joint ventures are initially recognised at cost and are accounted for by the equity method of accounting. Under the equity method, the investments in joint ventures are carried in the consolidated statement of financial position at cost. The carrying amount of the investment is adjusted to recognise changes in the Group's share of the net assets of a joint venture since the acquisition date less any impairment in the value of individual investments. The Group's share of post-acquisition profits or losses of a joint venture is recognised in profit or loss. The aggregate of the Group's share of profit or loss of the joint venture is shown on the face of the consolidated statement of profit and loss and represents profit or loss after tax and non-controlling interest in the subsidiaries of the joint venture. Unrealised gains and losses on transactions between the Group and a joint venture are eliminated to the extent of the Group's interest in the joint venture.

Any excess of the cost of acquisition over the Group's share of the net fair value of the identifiable assets, liabilities and contingent liabilities of a joint venture at the date of acquisition is recognised as goodwill. The goodwill is included within the carrying amount of the investment and is assessed for impairment as part of the investment. Any excess of the Group's share of the net fair value of the identifiable assets, liabilities and contingent liabilities over the cost of acquisition is recognised immediately in profit or loss.

When the Group's share of losses in a joint venture equals or exceeds its interest in the joint venture, the Group does not recognise further losses, unless the Group has incurred obligations or made payments on behalf of the joint venture.

At each reporting date, the Group determines whether there is objective evidence that the investment in the joint venture is impaired. If there is such evidence, the Group determines the amount of impairment as the difference between the recoverable amount of the joint venture and its carrying value, and then recognises the loss in the consolidated statement of profit or loss.

The accounting policies of a joint venture are aligned with those adopted by the Group where necessary, to ensure consistency.

3.5 Property, plant and equipment

Property, plant and equipment comprises oil and gas properties, machinery, furniture and fixtures and vessel costs.

Initial recognition

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Depreciation

Property, plant and equipment related to hydrocarbon production activities are generally depreciated on a unit of production basis over the proved and probable developed and undeveloped commercial reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. For the purposes of calculating depreciation, the value of oil and gas properties includes both historical capital expenditure and estimated future capital expenditure related to the development of undeveloped 2P reserves. Depreciation of other property, plant and equipment is calculated on the straight-line method so as to write off the cost amount of each asset to its residual value, over its estimated useful life. The useful life of each class is estimated as follows:

	Years
Buildings	12
Vessel cost	5-14
Plant and machinery	7-30
Furniture, fixtures and equipment	7

3.5 Property, plant and equipment *continued*

Depreciation of the assets in the course of construction commences when the assets are ready for their intended use, on the same basis as other assets of the same class.

An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement of profit or loss when the asset is derecognised.

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date.

Development costs

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells is capitalised within oil and gas properties in property, plant, and equipment on the consolidated statement of financial position.

Repairs, maintenance, and renovations

Expenditure for routine repairs and maintenance of property, plant and equipment is charged to the profit or loss in the year in which it is incurred. The cost of major improvements and renovations and other subsequent expenditure are included in the carrying amount of the asset when the recognition criteria of IAS 16 'Property, Plant and Equipment' are met. Major improvements and renovations capitalised are depreciated over the remaining useful life of the related asset.

3.6 Intangible assets

Computer software

Costs that are directly associated with identifiable and unique computer software products controlled by the Group and that will probably generate economic benefits exceeding costs beyond one year are recognised as intangible assets. Subsequently computer software is carried at cost less any accumulated amortisation and any accumulated impairment losses.

Costs associated with maintenance of computer software programs are recognised as an expense when incurred.

Computer software costs are amortised using the straight-line method over their useful lives, which commence when the computer software is available for use. Their amortisation expense is included in administration expenses.

Exploration and evaluation costs

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. Exploration and evaluation assets are accounted for using the successful efforts method of accounting.

Once the legal right to explore has been acquired, costs directly associated with exploration and evaluation are capitalised as exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated. These costs include licence acquisition costs, directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors and suppliers.

If no potentially commercial reserves are found, the exploration asset is tested for impairment. If potentially extractable hydrocarbons are found and, subject to further appraisal activity (e.g. by drilling further wells), have the potential to be developed commercially, the costs continue to be carried as exploration and evaluation cost while sufficient and continued progress is made in assessing the commerciality of the hydrocarbons. All such capitalised costs are subject to technical, commercial and management review as well as review for indicators of impairment at least once a year, to confirm the continued intention to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off to profit or loss.

When proved reserves of oil are identified and development is sanctioned by management, the relevant expenditure is assessed for impairment and any resulting impairment loss is recognised before reclassifying the balance to oil and gas properties within property, plant and equipment.

Accounting policies
continued

3.7 Impairment of non-financial assets

At each reporting date, the Group reviews the carrying amounts of its depreciable property, plant and equipment and intangible assets to determine whether there is any indication that those assets have suffered an impairment loss. Impairment is assessed at the level of cash-generating units (CGUs) which, in accordance with IAS 36 'Impairment of Assets', are identified as the smallest identifiable group of assets that generates cash inflows which are largely independent of the cash inflows from other assets. This is usually at the individual royalty, stream, oil and gas or working interest level for each property from which cash inflows are generated.

An impairment loss is recognised for the amount by which the asset's carrying value exceeds its recoverable amount, which is the higher of fair value less costs of disposal (FVLCD) and value-in-use (VIU). The future cash flow expected is derived using estimates of proven and probable reserves, a portion of resources that is expected to be converted into reserves and information regarding the mineral, stream and oil & gas properties, respectively, that could affect the future recoverability of the Company's interests. Discount factors are determined individually for each asset and reflect their respective risk profiles.

Assets are subsequently reassessed for indications that an impairment loss previously recognised may no longer exist. An impairment charge is reversed if the conditions that gave rise to the recognition of an impairment loss are subsequently reversed and the asset's recoverable amount exceeds its carrying amount. Impairment losses can be reversed only to the extent that the recoverable amount does not exceed the carrying value that would have been determined had no impairment been recognised previously.

Exploration and evaluation assets are tested for impairment when there is an indication that a particular exploration and evaluation project may be impaired. Examples of indicators of impairment include a significant price decline over an extended period, the decision to delay or no longer pursue the exploration and evaluation project, or an expiration of rights to explore an area. In addition, exploration and evaluation assets are assessed for impairment upon their reclassification to producing assets (oil and gas interest in property, plant and equipment). In assessing the impairment of exploration and evaluation assets, the carrying value of the asset would be compared to the estimated recoverable amount and any impairment loss recognised immediately in profit or loss.

3.8 Leasing

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. Leases where a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases.

Operating leases

The Group as lessee:

Rentals payable under operating leases are charged to profit or loss on a straight-line basis over the term of the relevant lease.

Benefits received and receivable as an incentive to enter into an operating lease as well as prepayments and any other premiums paid are spread on a straight-line basis over the lease term.

3.9 Financial instruments

Financial assets and financial liabilities are recognised when the Group becomes a party to the contractual provisions of the instrument.

Financial instruments are initially measured at fair value, plus transaction costs that are directly attributable to the acquisition of financial assets or the issuance of financial liabilities that are recorded at other than fair value through profit and loss.

Financial assets are classified into the following specified categories: financial instruments 'at fair value through profit and loss' (FVTPL); 'held to maturity investments'; 'available for sale (AFS) financial assets' and 'loans and receivables'. Financial liabilities are classified as FVTPL and other liabilities. The classification of financial instruments depends on the nature and purpose of the financial assets and is determined at the time of initial recognition. For the periods presented the Group's financial assets consist of 'loans and receivables' and FVTPL, and financial liabilities consist of FVTPL and other liabilities.

Financial instruments at fair value through profit or loss

FVTPL includes financial instruments held for trading (HFT) and financial instruments designated upon initial recognition at fair value through profit or loss. Financial instruments are classified as HFT if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as HFT. The Group has not designated any financial instruments at fair value through profit or loss. Financial instruments at fair value through profit or loss are carried in the consolidated statement of financial position at fair value with net changes in fair value presented as a gain or loss in the consolidated statement of profit or loss. The Group's financial instruments that have been classified as HFT are derivative instruments.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not HFT or designated at fair value though profit or loss.

Loans and receivables

Loans and receivables that have fixed or determinable payments and are not quoted in an active market are classified as loans and receivables. Loans and receivables are measured at initial recognition at fair value plus any directly attributable transaction costs, and are subsequently measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate, except for short-term receivables when the recognition of interest would be immaterial in the consolidated statement of profit and loss. The Group's loans and receivables consist of other non-current assets, cash and cash equivalents and trade and other receivables.

Impairment of financial assets

The Group assesses, at each reporting date, whether there is objective evidence that a financial asset or a group of financial assets is impaired. An impairment exists if one or more events that has occurred since the initial recognition of the asset (an incurred 'loss event'), has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganisation, and observable data indicating that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Group first assesses whether impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be, recognised are not included in a collective assessment of impairment.

The amount of any impairment loss identified is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not yet been incurred). The present value of the estimated future cash flows is discounted at the financial asset's original effective interest rate.

Accounting policies
continued

3.9 Financial instruments *continued*

The carrying amount of the asset is reduced through the use of an allowance account and the loss is recognised in the statement of profit or loss. Interest income (recorded as finance income in the statement of profit or loss) continues to be accrued on the reduced carrying amount and is accrued using the rate of interest used to discount the future cash flows for the purpose of measuring the impairment loss. Loans, together with the associated allowance, are written off when there is no realistic prospect of future recovery and all collateral has been realised or has been transferred to the Group. If, in a subsequent year, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognised, the previously recognised impairment loss is increased or reduced by adjusting the allowance account. If a write-off is later recovered, the recovery is credited consistent with where the impairment was recorded in the statement of profit or loss.

Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, and other financial liabilities, which include borrowings and trade and other payables. The Group does not have any financial liabilities classified as fair value through profit or loss except derivative instruments.

Other liabilities

Other financial liabilities are recognised initially at fair value, net of directly attributable transaction costs, and are subsequently measured at amortised cost using the effective interest method.

The effective interest rate method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that discounts the expected cash flows over the estimated life of the instrument to its net carrying amount. The effective interest rate amortisation is included as finance costs in the consolidated statement of profit or loss.

Derecognition of financial liabilities

A financial liability is derecognised when the obligation under the liability is discharged or cancelled, or it expires.

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

Equity instruments

Equity instruments issued by the Group are recorded at the proceeds received, net of direct issue costs.

Ordinary shares

Ordinary shares are classified as equity and measured at their nominal value. Any premiums received on issue of share capital above its nominal value are recognised as share premium within equity. Associated issue costs are deducted from share premium.

3.9 Financial instruments *continued*

Compound instruments

The component parts of compound instruments (convertible notes) issued by the Group are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangements and the definitions of a financial liability and an equity instrument. A conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a fixed number of the Group's own equity instruments is an equity instrument.

At the date of issue, the fair value of the liability component is estimated using the prevailing market interest rate for similar non-convertible instruments. This amount is recorded as a liability at fair value and measured at amortised cost using the effective interest method until extinguished upon conversion or at the instrument's maturity date.

The conversion option classified as equity is determined by deducting the amount of the liability component from the fair value of the compound instrument as a whole. This is recognised and included in equity, net of income tax effects, and is not subsequently remeasured. In addition, the conversion option classified as equity will remain in equity until the conversion option is exercised, in which case, the balance recognised in equity will be transferred to share premium. When the conversion option remains unexercised at the maturity date of the convertible note, the balance recognised in equity will be transferred to other equity reserves. No gain or loss is recognised in profit or loss upon conversion or expiration of the conversion option.

Transaction costs that relate to the issue of the convertible notes are allocated to the liability and equity components in proportion to the allocation of the gross proceeds. Transaction costs relating to the equity component are recognised directly in equity. Transaction costs relating to the liability component are included in the carrying amount of the liability component and are amortised over the lives of the convertible notes using the effective interest method.

If a conversion option does not meet the definition of an equity instrument, it is classified as a derivative. The conversion option is initially recorded at fair value. The derivative is initially recorded at fair value with the difference between the fair value and the proceeds of issuance recorded as a liability. The derivative is subsequently remeasured with changes to fair value recorded in the consolidated statement of profit or loss.

3.10 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either in the principal market for the asset or liability or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

All assets and liabilities, for which fair value is measured or disclosed in the consolidated financial statements, are categorised within the fair value hierarchy, described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable

For assets and liabilities that are recognised in the consolidated financial statements on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by reassessing categorisation (based on the lowest-level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

Accounting policies
continued

3.11 Cash and cash equivalents

Cash and cash equivalents comprise cash in hand, demand deposits and also cash reserves retained as a bank security pledge in respect of bank guarantees (Note 13.2), with a maturity of three months or less that are subject to an insignificant risk of changes in their fair value.

The cash reserves retained as a bank security pledge in respect of bank guarantees are defined as restricted cash and held in designated bank deposits accounts to be used only for the purposes of the capital commitments. Release of cash from the accounts can only be made with the approval of the lender when specified expenditure milestones are met. The current and non-current classification of the bank security pledges is determined by the forecast expenditure of the capital commitments.

3.12 Inventories

Inventories comprise crude oil and by-product (sulphur), consumables and other spare parts. Inventories are stated at the lower of cost and net realisable value. Cost is determined using the monthly weighted average cost method. The cost of finished goods and work in progress comprises raw materials, direct labour, other direct costs and related production overheads. It does not include borrowing costs. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and estimated costs necessary to make the sale. Spare parts consumed within a year are carried as inventory and recognised in profit or loss when consumed.

The Group assesses the net realisable value of the inventories at the end of each year and recognises in the consolidated statement of profit or loss the appropriate valuation adjustment if the inventories are overstated. When the circumstances that previously caused impairment no longer exist or when there is clear evidence of an increase in the inventories' net realisable value due to a change in the economic circumstances, the amount thereof is reversed.

3.13 Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount can be made. Where the Group expects a provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risk and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (when the effect of the time value of money is material).

Decommissioning provision

The Group recognises a provision for decommissioning cost and, more specifically, a provision for future restoration of environment disturbed, as of the reporting date, as a result of past drilling activity and in line with prevailing environmental legislation or binding practices. According to the Prinos concession agreement ratified by Greek law, the Group is obliged to plug only the wells opened resulting from own drilling activities. The amount recognised is the estimated cost of restoration, discounted to its present value. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related oil & gas property. The provision is measured at each reporting date and is appropriately adjusted to reflect the present value of the expenses required to fulfil the obligation. Changes in the estimated timing of restoration or restoration cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment.

The unwinding of the discount on the decommissioning provision is recognised in profit or loss within finance costs.

3.14 Revenue

Revenue is measured at the fair value of the consideration received or receivable, net of discounts and revenue indirect taxes.

Revenue is recognised when the amount of revenue can be measured reliably, it is probable that the economic benefits associated with the transaction will flow to the Group, the costs incurred or to be incurred can be measured reliably, and the recognition criteria for each of the Group's different activities have been met. These activity-specific recognition criteria are described below.

Sale of crude oil and by-products

Revenue from sale of crude oil and by-products is recognised when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. This generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism.

Rendering of services

Revenue from technical advisory services is recognised in the period in which the services are rendered by reference to the stage of completion of the specific service transaction, assessed on the basis of the actual service provided as a proportion of the total services to be provided.

Finance income

Finance income is accrued by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

3.15 Retirement benefit costs

State-managed retirement benefit scheme

Payments made to state-managed retirement benefit schemes (e.g. Government Social Insurance Fund) are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution plan. The Group's contributions are expensed as incurred and are included in staff costs. The Group has no legal or constructive obligations to pay further contributions if the government scheme does not hold sufficient assets to pay all employees' benefits relating to employee service in the current and prior periods.

Defined benefit plan

The Group operates an unfunded defined benefit plan in which a lump sum amount is specified and is payable at the termination of employees' service based on such factors as the length of the employees' service and their salary. The liability recognised for the defined benefit plan is the present value of the defined benefit obligation at the reporting date.

The cost of providing benefits is determined using the projected unit credit method, with actuarial valuations being carried out at each reporting date. The assumptions used in the actuarial valuations are developed by management with the assistance of independent actuaries.

Service costs on the defined benefit plan are included in staff costs. Interest expense on the defined benefit liability is included in finance costs. Gains and losses resulting from other remeasurements of the defined benefit liability are included in other comprehensive income.

3.16 Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalisation.

Excluded from the above capitalisation policy are any qualifying assets that are inventories that are produced in large quantities on a repetitive basis.

Borrowing costs include interest expense on loans, and bank overdrafts on an effective rate basis, and other bank charges, and are included in the consolidated statement of profit or loss.

Accounting policies
continued

3.17 Tax

Income tax expense represents the sum of current and deferred tax.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the consolidated financial statements because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are never taxable or deductible. The Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

Deferred tax is recognised on temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax bases used in the computation of taxable profit, based on tax rates that have been enacted or substantively enacted by the reporting date. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised. No deferred tax is recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Current and deferred tax assets and corresponding liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its tax assets and liabilities on a net basis.

Significant estimates are made in determining the tax liability for income taxes. The tax treatment of some transactions and calculations is uncertain and is yet to be agreed with the tax authorities in a number of jurisdictions. The Group recognises tax provision liabilities for anticipated tax issues based on whether it is probable – defined as more likely than not – that additional taxes will be due. This assessment is based on all available evidence and, where appropriate, in the light of external advice. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax liability in the period in which such determination is made.

The Group has recognised deferred tax assets in respect of losses and other temporary differences to the extent that it is probable that there will be future taxable profits against which the losses and other temporary differences can be utilised. The Group has considered their carrying value at each balance sheet date and concluded that, based on management's estimates, sufficient taxable profits will be generated in future years to recover such recognised deferred tax assets. These estimates are based on forecast performance and, where tax losses are subject to expiration, the estimates take into account the expected reversal patterns of taxable temporary differences compared to the future reversal of deductible temporary differences.

3.18 Non-current assets and liabilities classified as held for sale and discontinued operations

Non-current assets (and disposal groups) classified as held for sale are measured at the lower of carrying amount and fair value less costs of disposal. Non-current assets and disposal groups are classified as held for sale if their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset (or disposal group) is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year of the date of classification.

When the Group is committed to a sale plan involving loss of control of a subsidiary, all of the assets and liabilities of that subsidiary are classified as held for sale when the criteria described above are met, regardless of whether the Group will retain a non-controlling interest in its former subsidiary after the sale.

When the Group is committed to a sale plan involving disposal of an investment in an associate, or a portion of an investment in an associate, the investment or the portion of the investment in the associate that will be disposed of is classified as held for sale when the criteria described above are met, and the Group discontinues the use of the equity method in relation to the portion that is classified as held for sale. Any retained portion of an investment in an associate that has not been classified as held for sale continues to be accounted for using the equity method. The Group discontinues the use of the equity method at the time of disposal when the disposal results in the Group losing significant influence over the associate. After the disposal takes place, the Group accounts for any retained interest in the associate in accordance with IAS 39 'Financial Instruments: Recognition and Measurement' unless the retained interest continues to be an associate, in which case the Group uses the equity method (see the accounting policy regarding investments in associates above) (please refer also to Note 9).

3.19 Equity, reserves and dividend payments

Share capital represents the nominal (par) value of shares that have been issued. Share premium includes any premiums received on issue of share capital. Any transaction costs associated with the issuing of shares are deducted from share premium, net of any related income tax benefits.

Other components of equity include the following:
- remeasurement of net defined benefit liability – comprises the actuarial losses from changes in demographic and financial assumptions and the return on plan assets (see Note 3.15)
- translation reserve – comprises foreign currency translation differences arising from the translation of financial statements of the Group's foreign entities into euros and translation reserves from the translation to the Group's presentation currency US$ (see Note 3.2).

Retained earnings includes all current and prior period retained profits.

All transactions with owners of the parent are recorded separately within equity.

Dividend distributions payable to equity shareholders are included in other liabilities when the dividends have been approved in a general meeting prior to the reporting date.

3.20 New standards, amendments to standards and interpretations

The accounting policies adopted are consistent with those of the previous financial year except for the following amended IFRSs which have been adopted by the Group and Company as of 1 January 2017:

The below amendments did not have a significant impact on the Company and consolidated financial statements for the year ended 31 December 2017.

The consolidated financial statements have been prepared using the significant accounting policies and measurement bases summarised below.

- **IAS 12: Recognition of Deferred Tax Assets for Unrealised Losses (Amendments)**

The objective of the amendments is to clarify the requirements of deferred tax assets for unrealised losses, in order to address diversity in practice in the application of IAS 12 Income Taxes. The specific issues where diversity in practice existed relate to: the existence of a deductible temporary difference upon a decrease in fair value, recovering an asset for more than its carrying amount, probable future taxable profit and combined versus separate assessment.

- **IAS 7: Disclosure Initiative (Amendments)**

The objective of the amendments is to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The amendments specify that one way to fulfil the disclosure requirement is by providing a tabular reconciliation between the opening and closing balances in the statement of financial position for liabilities arising from financing activities, including changes from financing cash flows, changes arising from obtaining or losing control of subsidiaries or other businesses, the effect of changes in foreign exchange rates, changes in fair values and other changes.

- The **IASB has issued the Annual Improvements to IFRSs 2014-2016 Cycle**, which is a collection of amendments to IFRSs. The following annual improvement has not yet been endorsed by the EU. This improvement did not have an effect on the Group financial statements:
  - **IFRS 12 Disclosure of Interests in Other Entities**: The amendments clarify that the disclosure requirements in IFRS 12, other than those of summarised financial information for subsidiaries, joint ventures and associates, apply to an entity's interest in a subsidiary, a joint venture or an associate that is classified as held for sale, held for distribution, or as discontinued operations in accordance with IFRS 5.

Accounting policies
continued

3.21 Standards issued but not yet effective and not early adopted

IFRS 9 Financial Instruments: Classification and Measurement

The standard is effective for annual periods beginning on or after 1 January 2018, with early application permitted. The final version of IFRS 9 Financial Instruments reflects all phases of the financial instruments project and replaces IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. The standard introduces new requirements for classification and measurement, impairment, and hedge accounting.

The Group plans to adopt the new standard on the required effective date and will not restate comparative information. During 2017, an impact assessment of IFRS 9 was performed.

Based on the above assessment the following impact from the adoption of the new standard is expected:
- There will be no impact on the Group's accounting for financial liabilities, as the new requirements only affect the accounting for financial liabilities that are designated at fair value through profit or loss and the Group does not have any such liabilities.
- Financial assets currently held will continue to be measured on the same basis under IFRS 9, and accordingly, the Group does not expect the new guidance to have a significant impact on the classification and measurement of its financial assets.
- The new impairment model requires the recognition of impairment provisions based on expected credit losses (ECL) rather than only incurred credit losses as is the case under IAS 39. The Group will apply the simplified approach and record lifetime expected losses on all trade receivables. Based upon an assessment carried out, the Group has determined that, upon adoption, the loss allowance will not increase.
- The new hedge accounting rules will align the accounting for hedging instruments more closely with the Group's risk management practices. It appears that the Group's current hedge relationships would qualify as continuing hedges upon the adoption of IFRS 9. Accordingly, the Group does not expect a significant impact on the accounting for its hedging relationships.
- The new standard also introduces expanded disclosure requirements and changes in presentation. These are expected to change the nature and extent of the Group's disclosures about its financial instruments, particularly in the year of the adoption of the new standard.

IFRS 15: Revenue from Contracts with Customers

The standard is effective for annual periods beginning on or after 1 January 2018. IFRS 15 establishes a five-step model that will apply to revenue earned from a contract with a customer (with limited exceptions), regardless of the type of revenue transaction or the industry. The standard's requirements will also apply to the recognition and measurement of gains and losses on the sale of some non-financial assets that are not an output of the entity's ordinary activities (e.g. sales of property, plant and equipment or intangibles). Extensive disclosures will be required, including: disaggregation of total revenue; information about performance obligations; changes in contract asset and liability account balances between periods, and key judgements and estimates.

The Group plans to adopt the new standard on the required effective date using the modified retrospective method. Based on the Group's assessment of IFRS 15 completed in 2017, no material differences from the current accounting policies were identified. Therefore, the new standard is not expected to have a significant impact on the Group's consolidated financial statements upon adoption.

IFRS 15: Revenue from Contracts with Customers (clarifications)

The clarifications apply for annual periods beginning on or after 1 January 2018 with earlier application permitted. The objective of the clarifications is to clarify the IASB's intentions when developing the requirements in IFRS 15 Revenue from Contracts with Customers, particularly the accounting of identifying performance obligations amending the wording of the 'separately identifiable' principle, of principal versus agent considerations including the assessment of whether an entity is a principal or an agent as well as applications of control principle and of licensing providing additional guidance for accounting of intellectual property and royalties. The clarifications also provide additional practical expedients for entities that either apply IFRS 15 fully retrospectively or that elect to apply the modified retrospective approach. Management has assessed that the amendments do not affect the consolidated financial statements.

IFRS 16: Leases

The standard is effective for annual periods beginning on or after 1 January 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer ('lessee') and the supplier ('lessor'). The new standard requires lessees to recognise most leases on their financial statements. Lessees will have a single accounting model for all leases, with certain exemptions. Lessor accounting is substantially unchanged.

3.21 Standards issued but not yet effective and not early adopted *continued*

The standard will affect primarily the accounting for the Group's operating leases. However, the Group has assessed that the amendments will not have a material impact on the consolidated financial statements. This is due to the fact that some of the commitments may be covered by the exception for short-term and low-value leases and some commitments may relate to arrangements that will not qualify as leases under IFRS 16.

Conceptual Framework in IFRS standards

The IASB issued the revised Conceptual Framework for Financial Reporting on 29 March 2018. The Conceptual Framework sets out a comprehensive set of concepts for financial reporting, standard setting, guidance for preparers in developing consistent accounting policies and assistance to others in their efforts to understand and interpret the standards. IASB also issued a separate accompanying document, Amendments to References to the Conceptual Framework in IFRS Standards, which sets out the amendments to affected standards in order to update references to the revised Conceptual Framework. It's objective is to support transition to the revised Conceptual Framework for companies that develop accounting policies using the Conceptual Framework when no IFRS Standard applies to a particular transaction. For preparers who develop accounting policies based on the Conceptual Framework, it is effective for annual periods beginning on or after 1 January 2020.

IAS 19: Plan Amendment, Curtailment or Settlement (amendments)

The amendments are effective for annual periods beginning on or after 1 January 2019 with earlier application permitted. The amendments require entities to use updated actuarial assumptions to determine current service cost and net interest for the remainder of the annual reporting period after a plan amendment, curtailment or settlement has occurred. The amendments also clarify how the accounting for a plan amendment, curtailment or settlement affects applying the asset ceiling requirements. These amendments have not yet been endorsed by the EU. The Group will examine the impact of the above on its consolidated financial statements.

IFRS 2: Classification and Measurement of Share-based Payment Transactions (amendments)

The Amendments are effective for annual periods beginning on or after 1 January 2018 with earlier application permitted. The Amendments provide requirements on the accounting for the effects of vesting and non-vesting conditions on the measurement of cash-settled share-based payments, for share-based payment transactions with a net settlement feature for withholding tax obligations and for modifications to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled.

IAS 40: Transfers to Investment Property (amendments)

The amendments are effective for annual periods beginning on or after 1 January 2018 with earlier application permitted. The amendments clarify when an entity should transfer property, including property under construction or development, into or out of investment property. The amendments state that a change in use occurs when the property meets, or ceases to meet, the definition of investment property and there is evidence of the change in use. A mere change in management's intentions for the use of a property does not provide evidence of a change in use.

IFRS 9: Prepayment Features with Negative Compensation (amendment)

The amendment is effective for annual reporting periods beginning on or after 1 January 2019 with earlier application permitted. The amendment allows financial assets with prepayment features that permit or require a party to a contract either to pay or receive reasonable compensation for the early termination of the contract (so that, from the perspective of the holder of the asset there may be 'negative compensation'), to be measured at amortised cost or at fair value through other comprehensive income. The Group will examine the impact of the above on its financial statements, though it is not expected to have any.

IAS 28: Long-term Interests in Associates and Joint Ventures (amendments)

The amendments are effective for annual reporting periods beginning on or after 1 January 2019 with earlier application permitted. The amendments relate to whether the measurement, in particular impairment requirements, of long-term interests in associates and joint ventures that, in substance, form part of the 'net investment' in the associate or joint venture should be governed by IFRS 9, IAS 28 or a combination of both. The amendments clarify that an entity applies IFRS 9 Financial Instruments, before it applies IAS 28, to such long-term interests for which the equity method is not applied. In applying IFRS 9, the entity does not take account of any adjustments to the carrying amount of long-term interests that arise from applying IAS 28. These amendments have not yet been endorsed by the EU. The Group will examine the impact of the above on its financial statements, though it is not expected to have any.

Accounting policies
continued

3.21 Standards issued but not yet effective and not early adopted *continued*

- **IFRIC INTERPRETATION 22: Foreign Currency Transactions and Advance Consideration**

  The interpretation is effective for annual periods beginning on or after 1 January 2018 with earlier application permitted. The interpretation clarifies the accounting for transactions that include the receipt or payment of advance consideration in a foreign currency. The interpretation covers foreign currency transactions when an entity recognises a non-monetary asset or a non-monetary liability arising from the payment or receipt of advance consideration before the entity recognises the related asset, expense or income. The interpretation states that the date of the transaction, for the purpose of determining the exchange rate, is the date of initial recognition of the non-monetary prepayment asset or deferred income liability. If there are multiple payments or receipts in advance, then the entity must determine a date for the transactions for each payment or receipt of advance consideration. The Group will examine the impact of the above on its financial statements.

- The **IASB has issued its Annual Improvements to IFRSs (2014-2016 cycle),** which is a collection of amendments to IFRSs. The amendments are effective for annual periods beginning on or after 1 January 2018 for IFRS 1 First-time Adoption of International Financial Reporting Standards and for IAS 28 Investments in Associates and Joint Ventures. Earlier application is permitted for IAS 28 Investments in Associates and Joint Ventures. These annual improvements have not yet been endorsed by the EU. The Group will examine the impact of the above on its financial statements, though it is not expected to have any.
  - **IAS 28 Investments in Associates and Joint Ventures:** The amendments clarify that the election to measure at fair value through profit or loss an investment in an associate or a joint venture that is held by an entity that is a venture capital organisation, or other qualifying entity, is available for each investment in an associate or joint venture on an investment-by-investment basis, upon initial recognition.

- **IFRIC INTERPRETATION 23: Uncertainty over Income Tax Treatments**

  The interpretation is effective for annual periods beginning on or after 1 January 2019 with earlier application permitted. The interpretation addresses the accounting for income taxes when tax treatments involve uncertainty that affects the application of IAS 12. The interpretation provides guidance on: considering uncertain tax treatments separately or together, examination by tax authorities, the appropriate method to reflect uncertainty, and accounting for changes in facts and circumstances. This Interpretation has not yet been endorsed by the EU. The Group will examine the impact of the above on its financial statements.

  The **IASB has issued its Annual Improvements to IFRSs (2015-2017 cycle)**, which is a collection of amendments to IFRSs. The amendments are effective for annual periods beginning on or after 1 January 2019 with earlier application permitted. These annual improvements have not yet been endorsed by the EU. The Group will examine the impact of the elements below on its financial statements:
  - **IFRS 3 Business Combinations** and **IFRS 11 Joint Arrangements:** The amendments to IFRS 3 clarify that when an entity obtains control of a business that is a joint operation, it remeasures previously held interests in that business. The amendments to IFRS 11 clarify that when an entity obtains joint control of a business that is a joint operation, the entity does not remeasure previously held interests in that business.
  - **IAS 12 Income Taxes:** The amendments clarify that the income tax consequences of payments on financial instruments classified as equity should be recognised according to where the past transactions or events that generated distributable profits has been recognised.
  - **IAS 23 Borrowing Costs:** The amendments clarify paragraph 14 of the standard that, when a qualifying asset is ready for its intended use or sale, and some of the specific borrowing related to that qualifying asset remains outstanding at that point, that borrowing is to be included in the funds that an entity borrows generally.

4. Critical accounting estimates and judgements

The preparation of these consolidated financial statements in conformity with IFRS requires the use of accounting estimates and assumptions, and also requires management to exercise its judgement in the process of applying the Group's accounting policies.

Estimates, assumptions and judgement applied are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Although these estimates, assumptions and judgement are based on management's best knowledge of current events and actions, actual results may ultimately differ.

4.1 Critical judgements in applying the Group's accounting policies

The following are significant management judgements in applying the accounting policies of the Group that have the most significant effect on the consolidated financial statements:

Determination of a business

Determination of whether a set of assets acquired and liabilities assumed constitute a business may require the Group to make certain judgements. A business is a group of assets that includes inputs, outputs and processes that are capable of being managed together to provide a return to the Group and its shareholders. Classification of an acquisition as a business combination or an asset acquisition depends on whether the assets acquired constitute a business. Whether an acquisition is classified as a business combination or asset acquisition can have a significant impact on the entries made on or after acquisition.

In 2016, the Group acquired the remaining 50% of the equity in Energean Israel Limited. The Group concluded that the acquisition did not meet the definition of a business since in acquisition the fair value of the gross assets acquired was not concentrated in a single identifiable asset, and accordingly, the acquisition was accounted for as the acquisition of an asset. The accounting and further detail on the judgement made is set out in Note 9.

Functional currency

The functional currency for the Company and each of its subsidiaries is the currency of the primary economic environment in which the entity operates. Note 3.2 describes the functional currency of each of the entities within the Group. The determination of the functional currency of Energean Oil and Gas S.A. involves certain judgements to determine the primary economic environment. As Energean Oil and Gas S.A.'s capital expenditure, payroll cost, energy costs and exploration and evaluation costs are all predominantly denominated in euro, the Group has determined that the functional currency of the company is the euro. The Group reconsiders the functional currency of its entities if there is a change in events and conditions which determined the primary economic environment.

4.2 Estimation uncertainty

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities are discussed below:

Fair value measurements and valuation processes

Some of the Group's assets and liabilities are measured at fair value for financial reporting purposes. In estimating the fair value of an asset or a liability the Group uses market-observable data to the extent that it is possible. Where Level 1 inputs are not available, as is the case for estimating a fair value for the convertible loan notes (see Note 9) and the option to purchase Energean Israel Class B shares (see Note 31.4) the Group has used a combination of Level 2 and Level 3 inputs to estimate the fair value.

The Chief Financial Officer reports the valuations to the Board of Directors of the Group every six months to explain the cause of fluctuations in the fair value of the assets and liabilities.

Information about the valuation technique and inputs used in determining the fair value of the convertible loan notes and the option to purchase Energean Israel Class B shares is disclosed in Note 34.2.

Accounting policies
continued

4.2 Estimation uncertainty *continued*

Impairment of non-financial assets

▶ Impairment assessment of property, plant and equipment

The Group assesses impairment at each reporting date by evaluating conditions specific to the Group that may lead to impairment of assets. Where an indicator of impairment exists, the recoverable amount (which is the higher of fair value less costs to sell and value in use) of the cash-generating unit to which the assets belong is then estimated based on the present value of future discounted cash flows. For oil and gas assets, the expected future cash flow estimation is based on a number of factors, variables and assumptions, the most important of which are estimates of reserves, future production profiles, oil prices and costs. In most cases, the present value of future cash flows is most sensitive to estimates of future oil price, estimates of reserves, estimates of development costs and discount rates. A change in the assumptions could materially change the recoverable amount. In the event that future circumstances vary from these assumptions, the recoverable amount of the Group's development and production assets could change materially and result in impairment losses or the reversal of previous impairment losses.

The fields of Prinos, Prinos North and Epsilon are grouped together in one cash-generating unit (CGU) and reviewed annually for impairment. The carrying value of Prinos CGU as of 31 December was US$303.9 million. The recoverable amount of the Prinos CGU as of 31 December was estimated above its carrying value therefore no impairment losses were recorded in the Group's profit or loss.

Further details of the Group's economic environment are provided in Note 33. Based on the evaluation performed, No reasonably possible change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Further details about the carrying value of property, plant and equipment are shown in Note 6 of the consolidated financial statements.

▶ Impairment assessment of exploration and evaluation costs

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement in determining whether future economic benefits are likely from either future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves, or whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when this new information becomes available. Further details about the carrying value of exploration and evaluation costs are shown in Note 6 to the consolidated financial statements.

Hydrocarbon reserve and resource estimates

The Group's oil and gas development and production properties are depreciated on a unit of production basis at a rate calculated by reference to developed and undeveloped proved and probable commercial reserves (2P developed and undeveloped) which are estimated to be recoverable with existing and future developed facilities using current operating methods, as determined in accordance with Petroleum Resources Management System published by Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists.

Commercial reserves are determined using estimates of oil in place, recovery factors and future oil prices. The level of estimated commercial reserves is also a key factor in assessing whether the carrying value of any of the Group's oil and gas properties has been impaired.

As the economic assumptions used may change and as additional geological information is produced during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results which include:

- Depreciation and amortisation charges in profit or loss may change, where such charges are determined using the unit of production method, or where the useful life of the related assets changes
- Impairment charges in profit or loss
- Provisions for decommissioning may change where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities
- The recognition and carrying value of deferred tax assets and liabilities may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

4.2 Estimation uncertainty *continued*

The impact upon commercial reserves and the aggregate depletion charge for the year of a +/- 10% fluctuation in the forward Brent oil price assumption as well as a +/-10% fluctuation in the forward foreign exchange rate (euro to USD) are presented in the table below. Management monitors the impact on the commercial reserves and the depletion charge at a Group level. The Group's carrying amount of oil and gas properties for all periods presented is shown in Note 6.

Average forward floating Brent price (amounts in US$) per annum	Developed and Undeveloped, proved and probable commercial reserves in thousands of barrels	Depreciation (in US$ 000)
-20% fluctuation of the forward Brent oil price assumption	37,322	17.227
Base scenario	38,191	16.820
+20% fluctuation of the forward Brent oil price assumption	38,191	16,820

Average forward floating FX rate (USD to euro) per annum (based on above forward floating Brent prices)	Developed and undeveloped, Proved and probable commercial reserves in thousands of barrels	Depreciation (in US$ 000)
-30% fluctuation of the forward foreign exchange rate (Euro to USD)	38,191	13,343
Base scenario	38,191	16,820
+30% fluctuation of the forward foreign exchange rate (Euro to USD)	37,322	19,774

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement in determining whether future economic benefits are likely from either future exploitation or sale, or where activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on sub-classification, and these estimates directly impact the point of deferral of exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when the new information becomes available.

Retirement benefit obligation

The cost of defined benefit pension plans is determined using actuarial valuations. The actuarial valuation involves making assumptions about discount rates, future salary increases, mortality rates and future pension increases where necessary. The Group sets these assumptions with the assistance of independent professional actuaries. Due to the long-term nature of these plans, such estimates are subject to significant uncertainty. The assumptions used may vary from year to year which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets. Further details are shown in Note 18 to the consolidated financial information.

Accounting policies
continued

4.2 Estimation uncertainty *continued*

Income taxes

Significant estimates are made in determining the tax liability for income taxes. The tax treatment of some transactions and calculations is uncertain and has yet to be agreed with the tax authorities in a number of jurisdictions. The Group recognises tax provision liabilities for anticipated tax issues based on whether it is probable, defined as more likely than not, that additional taxes will be due. This assessment is based on all available evidence and, where appropriate, in the light of external advice. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax liability in the period in which such determination is made.

The Group has recognised deferred tax assets in respect of losses and other temporary differences to the extent that it is probable that there will be future taxable profits against which the losses and other temporary differences can be utilised. The Group has considered their carrying value at each balance sheet date and concluded that, based on management's estimates, sufficient taxable profits will be generated in future years to recover such recognised deferred tax assets. These estimates are based on forecast performance and where tax losses are subject to expiration, the estimates take into account the expected reversal patterns of taxable temporary differences compared to the future reversal of deductible temporary differences.

Deferred tax assets recognised from carried forward unused tax losses for the Group amounted to US$80,571 for the year ended 31 December 2017 (year ended 31 December 2016: US$56,296).

The Directors regard the deferred tax asset in relation to tax losses and other temporary differences as recoverable, despite the loss-making situation that currently exists, based on their best estimate of future sources of taxable income for the Group.

Recoverability of Kavala subsidies receivable

In December 2015, Kavala Oil SA filed a petition against OAED, the public body for employment and social inclusion in Greece, and the Greek state itself, seeking the payment of €2.5 million (plus interest). This claim is based on the provisions of Art. 21 of the Law Act No 1767/1988 and the Ministerial Decree No 31370/1988, by which Kavala Oil SA believes it was entitled to receive the abovementioned sum as financial support under the action plan (co-funding by national and EU instruments) for promoting sustainable employment in underdeveloped or deprived districts of Greece, such as the area of Kavala.

Following several postponements of the hearing initiated by the Greek state, the hearing took place on 14 June 2017. The Group is of the view, based on legal advice, this petition will prevail and has therefore included a balance within trade and other receivables (Note 12).

Notes to the consolidated financial statements

5. Segmental reporting

The information reported to the Group's Chief Executive Officer and Chief Financial Officer (Chief Operating Decision Makers) for the purposes of resource allocation and assessment of segment performance is focused on five operating segments: Greece (including the production asset of Prinos and the non-producing exploration assets of Ioannina and Katakolo), Israel (including 50% of the Karish and Tanin assets), Egypt (including the non-producing exploration asset of West Kom Ombo), Montenegro (including two non-producing exploration assets) and new ventures. Factors considered to identify the operating segments of the Group are geographical and stage of development.

The operating results of each operating segment are regularly reviewed by the Group's Chief Operating Decision Makers in order to make decisions about the allocation of resources and to assess their performance. The Group's Chief Operating Decision Makers evaluate segmental performance on the basis of adjusted EBITDAX, which is defined as profit/(loss) from continuing operations before tax less depreciation and amortisation, exploration and evaluation expenses, other income, other expenses, finance costs, finance income, gain/(loss) on derivative instruments and net foreign exchange gain/(loss). Adjusted EBITDAX is used by the Chief Operating Decision Makers as the profit measure for the review of the segment operations. The Greece segment comprises the production asset of the Prinos area (including Prinos, Prinos North, South Kavala and Epsilon fields) and north-east Greece (exploration assets of Ioannina and Katakolo). The Group's reportable segment under IFRS 8 Operating Segments is Greece. Segments that do not exceed the quantitative thresholds for reporting information about operating segments have been included in Other.

The following tables present revenue and certain asset information regarding the Group's reportable segments for the years ended 31 December 2017 and 2016.

Segment revenues, results and reconciliation to profit before tax

The following is an analysis of the Group's revenue, results and reconciliation to profit before tax by reportable segment:

	Greece (US$ 000)	Other (US$ 000)	Intercompany transactions and elimination adjustments (US$ 000)	Total (US$ 000)
Year ended 31 December 2017				
Revenue	55,445	4,379	(2,072)	57,752
Adjusted EBITDAX	21,125	(943)	494	20,676
Reconciliation to profit/(loss) before tax:			–	
Depreciation and amortisation expenses	(17,946)	(62)	–	(18,008)
Exploration and evaluation expenses	(340)	(9,664)	38	(9,966)
Other expenses	(7,690)	(497)	–	(8,187)
Other income	245	1,540	4	1,789
Finance income	22,130	23,590	(45,706)	14
Finance costs	(29,814)	(38,552)	45,426	(22,940)
Gain on derivative	–	25,786	–	25,786
Net foreign exchange gain/(loss)	36,198	272	(227)	36,243
Profit/(loss) from continuing operations before tax	**23,908**	**1,470**	**29**	**25,407**
Year ended 31 December 2016				
Revenue	39,724	2,985	(2,985)	39,724
Adjusted EBITDAX	16,072	999	(869)	16,202
Reconciliation to profit/(loss) before tax				
Depreciation and amortisation expenses	(21,499)	–	–	(21,499)
Exploration and evaluation expenses	–	(1,953)	820	(1,133)
Other expenses	(4,480)	(208)	–	(4,688)
Other income	387	55	(194)	248
Finance income	327	29,375	(29,375)	327
Finance costs	(30,068)	(28,730)	29,487	(29,311)
Net foreign exchange gain/(loss)	(9,982)	(96)	35	(10,043)
Profit/(loss) from continuing operations before tax	**(49,243)**	**(558)**	**(96)**	**(49,897)**

The Group supplies the produced Prinos crude oil to BP Oil International Ltd until the later of: a) the expiry of the agreement on 31 July 2021 or b) the delivery of ten million barrels.

Notes to the consolidated financial statements
continued

5. Segmental reporting *continued*

The revenue recorded in Other Segments includes revenue from technical services provided by Energean International Limited to Energean Israel Limited subsequent to disposal of 50% of the shares in Energean Israel according to a Technical Services Agreement between the two companies (note 31).

The Exploration and evaluation expenses of 'Other Segment' in the period ended 31 December 2017 includes impairment losses of total amount US$8,007, (2016: US$nil) US$6,663 written off from intangible assets and US$1,344 from property plant and equipment, relating to exploration expenditure for West Kom Ombo in Egypt, the licence for which expired on 2 October 2017. There are no recoverable costs associated with West Kom Ombo and the asset has been fully written off in 2017. Furthermore the Group recognised a provision of US$1,285 for the remaining amount of the financial commitment.

6. Property, plant and equipment

Property, plant and equipment at cost	Oil and gas properties (US$ 000)	Land and buildings (US$ 000)	Property under construction (US$ 000)	Vessel and transportation means (US$ 000)	Plant and machinery (US$ 000)	Furniture, fixtures and equipment (US$ 000)	Total (US$ 000)
1 January, 2016	**237,034**	**490**	**24,241**	**5,939**	**47,956**	**1,455**	**317,115**
Additions	60,902	20	972	3	663	168	62,728
Exploration cost transferred from intangible assets	1,154						1,154
Capitalised depreciation	7,014						7,014
Disposals	–	–	–	(4,574)	–	–	(4,574)
Change in environmental rehabilitation provision	1,205	–	–	–	–	–	1,205
Foreign exchange impact	(10,647)	(16)	(816)	(128)	(1,556)	(44)	(13,207)
At 31 December 2016	**296,662**	**494**	**24,397**	**1,240**	**47,063**	**1,579**	**371,435**
Additions	61,113	13	2,354	213	1,903	145	65,741
Capitalised depreciation	2,388	–	–	–	–	–	2,388
Change in environmental rehabilitation provision	2,876	–	–	–	–	–	2,876
Foreign exchange impact	33,077	81	7,054	443	1,464	(103)	42,016
31 December 2017	**396,116**	**588**	**33,805**	**1,896**	**50,430**	**1,621**	**484,456**

Accumulated depreciation and impairment	Oil and gas properties (US$ 000)	Land and buildings (US$ 000)	Property under construction (US$ 000)	Vessel and transportation means (US$ 000)	Plant and machinery (US$ 000)	Furniture, fixtures and equipment (US$ 000)	Total (US$ 000)
At 1 January 2016	**100,681**	**178**	**39**	**1,217**	**12,836**	**1,155**	**116,106**
Charge for the year	20,673	56	–	115	411	100	21,355
Disposals	–		–	(299)		–	(299)
Impairments	–	–	1,007	–	940	–	1,947
Capitalised depreciation to oil and gas properties	–	–	–	–	7,014	–	7,014
Foreign exchange impact	(4,106)	(7)	45	39	(807)	(32)	(4,868)
31 December 2016	**117,248**	**227**	**1,091**	**1,072**	**20,394**	**1,223**	**141,255**
Charge for the period	17,020	69	–	34	612	73	17,808
Capitalised depreciation to oil and gas properties	–	–	–	–	2,388	–	2,388
Impairment	–	–	1,344	–	–	–	1,344
Foreign exchange impact	12,952	(21)	0	423	(1,530)	(139)	11,685
At 31 December 2017	**147,220**	**275**	**2,435**	**1,529**	**21,864**	**1,157**	**174,480**
Net carrying amount							
At 31 December 2017	**248,895**	**313**	**31,370**	**367**	**28,567**	**464**	**309,976**
At 31 December 2016	**179,414**	**267**	**23,306**	**168**	**26,669**	**356**	**230,180**

6. Property, plant and equipment *continued*

The oil and gas properties opposite related to the Greek segment (the fields of Prinos, Prinos North and Epsilon) are depreciated at the same rate (see Note 3.5).

Borrowing costs capitalised for qualifying assets, included in 'Additions' of oil & gas properties and property under construction for the year ended 31 December 2017, amounted to US$1,258 (year ended 31 December 2016: US$3,992). The interest rates used were:

- 7.03% (for the year ended 31 December 2017)
- 15.66% (for the period 1 January 2016 to 31 May 2016) and 6.97% (for the period 1 June 2016 to 31 December 2016).

During the year ended 31 December 2014 and in view of its future drilling campaigns, the Group acquired and initiated the upgrade work of a drilling rig (Energean Force). The Group has issued a first preferred mortgage on the aforementioned Energean Force, in favour of the European Bank for Reconstruction and Development (EBRD) (see Note 15). The depreciation charge of the Energean Force has been capitalised in the oil and gas properties.

The Group recorded impairment and write-off charges on PP&E of US$1,344 for the year ended 31 December 2017 (year ended 31 December 2016: US$1,947). The impairment charges in 2017 relates to impairment of drilling materials in West Kom Ombo license and are recorded under 'exploration and evaluation expenses' in the profit or loss. The impairment charges in 2016 relate to machinery and other equipment used in operations.

Depreciation and impairment expenses for the periods has been recognised as follows:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Cost of sales	**17,640**	21,218
Exploration and evaluation expenses	**1,344**	–
Administration expenses	**168**	137
Capitalised depreciation in oil & gas properties	**2,388**	7,014
Total	**21,540**	28,369

6.1 Loss from disposal of property, plant and equipment

In the cash flow statement, loss from the disposal of sale of property, plant and equipment comprise:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Supply vessel (net book value)	**–**	4,275
Proceeds from sale	**–**	(2,698)
Loss from disposal	**–**	**1,577**

7. Intangible assets

Intangibles at cost	Computers and software (US$ 000)	Exploration and evaluation costs (US$ 000)	Total (US$ 000)
At 1 January 2016	**1,081**	**4,019**	**5,100**
Additions	299	5,201	5,500
Foreign exchange impact	(81)	(103)	(184)
Exploration cost transferred to oil & gas properties	–	(1,154)	(1,154)
31 December 2016	**1,299**	**7,963**	**9,262**
Additions	281	2,871	3,152
Write-off of exploration and evaluation costs	–	(6,663)	(6,663)
Disposal of exploration and evaluation cost	–	(1,000)	(1,000)
Exchange differences	82	440	522
31 December 2017	**1,662**	**3,611**	**5,273**

Notes to the consolidated financial statements
continued

7. Intangible assets *continued*

Accumulated amortisation and impairment	Computers and software (US$ 000)	Exploration and evaluation costs (US$ 000)	Total (US$ 000)
At 1 January 2016	**648**	**249**	**897**
Charge for the year	144		144
Exchange differences	(48)	(9)	(57)
31 December 2016	**744**	**240**	**984**
Charge for the period	200	–	200
Exchange differences	68	21	89
31 December 2017	**1,012**	**261**	**1,273**
Net carrying amount			
At 31 December 2017	**650**	**3,350**	**4,000**
At 31 December 2016	**555**	**7,723**	**8,278**

Disposal of exploration and evaluation cost

In March 2017, the Group agreed to farm out a 60% working interest and operatorship of the Ioannina licence to Repsol. The Group retains a 40% working interest as of 31 December 2017 (Note 1.2). According to the farm-out agreement:

- On the completion date Repsol paid to the Group the consideration of US$1 million for all past costs regarding the licence.
- Repsol will conduct the exploration of the Ioannina block, providing 90% of the committed investment up to US$25 million and 60% thereafter, in exchange for a 60% interest.

The disposal of exploration and evaluation cost included in the period ended 31 December 2017 relates to 60% of past expenditure in the Ioannina lease area. The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but re-designates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Write-off and impairments

The Group recognised US$6,663 million in exploration and evaluation expenses in the period ended 31 December 2017, relating to exploration expenditure for West Kom Ombo in Egypt. West Kom Ombo is an exploration block in Upper Egypt, the licence for which expired on 2 October 2017. There are no recoverable costs associated with West Kom Ombo and the asset has been fully written off in 2017.

Amortisation and impairment expenses and write-offs for the period have been recognised in profit or loss as follows:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Write-off of exploration and evaluation costs	**6,663**	–
Administration expenses	**200**	144
Total	**6,863**	**144**

8. Subsidiary companies

8.1 Details of subsidiaries

Name of subsidiary	Country of incorporation/registered office	Principal activities	At 31 December 2017 (%)	At 31 December 2016 (%)
Energean E&P Holdings Ltd[1]	36 Vyronos Avenue, 1506 Nicosia, Cyprus	Holding company	**100**	N/A
Energean Oil & Gas S.A.[2]	32 Kifissias Avenue, 151 25 Marousi Athens, Greece	Oil and gas exploration, development and production	**100**	100
Energean Drilling S.A.[3]	32 Kifissias Avenue, 151 25 Marousi Athens, Greece	Oil and gas exploration, development and production	**N/A**	N/A
Kavala Oil S.A.[4]	P.O. BOX 8, 64006 Nea Karvali, Kavala, Greece	Provision of oil and gas support services	**99.92**	99.92
Energean International Limited[5]	36 Vyronos Avenue, 1506 Nicosia, Cyprus	Oil and gas exploration, development and production	**100**	100
Energean Israel Limited[6] (Note 9)	36 Vyronos Avenue, 1506 Nicosia, Cyprus	Oil and gas exploration, development and production	**0**	100
Energean Montenegro Limited[7]	36 Vyronos Avenue, 1506 Nicosia, Cyprus	Oil and gas exploration, development and production	**100**	100

1 Energean E&P Holdings Limited was the holding company of the Group until 30 June 2017, when it became a wholly-owned subsidiary of Energean Oil & Gas plc.
2 Energean Oil & Gas S.A. is a subsidiary of Energean E&P Holdings Limited. On 8 December 2014, Energean Oil & Gas S.A. exercised its right to convert its preference shares in Kavala Oil S.A. to common shares to hold a 99.9% participating interest. This conversion was effective in March 2015 (as described in Note 10).
3 On 15 June 2016 Energean Drilling S.A. was merged with Energean Oil & Gas S.A.
4 Kavala Oil S.A. is a subsidiary of Energean Oil & Gas S.A.
5 Energean International Limited is a subsidiary of Energean E&P Holdings Limited.
6 As of 31 December 2017, the Group owns 0% of the economic interest and 50% of the voting rights in Energean Israel Limited. As of 31 December 2016, the Group owned 100% of the economic interest in Energean Israel Limited. The Group's interest in the share capital of Energean Israel Limited is described in Note 9.
7 On 29 June 2016 Energean Montenegro Limited was formed as the licence-holding vehicle for the application and subsequent award of Blocks 26 and 30 in Montenegro.

8.2 Corporate information and activities of main subsidiaries

Energean Oil & Gas S.A.

Energean Oil & Gas S.A. is engaged in the exploration, extraction and trading of oil and gas. Energean Oil & Gas S.A. was established in 2007 in Greece.

In December 2007, Energean Oil & Gas S.A. acquired Kavala Oil S.A. ('Kavala Oil'), the sole oil and gas production company in Greece, under a licence granted by the Greek State under Law 2779/1999 ('the Licence') for the exploration and production of the crude oil and gas reserves of Prinos and the South Kavala field ('the exploitation areas').

In June 2009, the exploitation areas were assigned by Kavala Oil to Energean Oil & Gas S.A, under an assignment agreement entered into in line with the licence. Under the assignment agreement Kavala Oil remained the Group operating company in respect of the exploitation areas of Prinos. From June 2009 Energean Oil & Gas S.A. became the concession holder of the Prinos, Prinos North, Epsilon and South Kavala oil & gas licences as per Law 2779/1999 as amended by Law 4135/2013. Both Energean Oil & Gas S.A. and Kavala Oil remain jointly and severally liable towards the Greek state in complying with all terms and obligations.

Energean Oil & Gas S.A. also holds a 60% working interest in the Ioannina onshore block in western Greece, as well as a 100% working interest in the 25-year exploitation licence of the Katakolo offshore field.

Notes to the consolidated financial statements
continued

8.2 Corporate information and activities of main subsidiaries *continued*

Energean Israel Limited

Please refer to Note 9 below.

9. Investments in Energean Israel

9.1 Details of the joint venture

Energean Israel Limited (formerly Ocean Energean Oil and Gas Limited) was incorporated in Cyprus on 22 July 2014 as a private company with limited liability under the Companies Law, Cap. 113. Its registered office is at Vyronos 36, Nicosia Tower Center, 8th floor, 1096, Nicosia, Cyprus.

The principal activity of Energean Israel Limited is to act, work and operate as an international offshore drilling contractor and/or oil operator, providing oilfield services for offshore oil and gas mining, exploration and production.

As of 31 December 2015 and 2014, Energean Israel Limited was a 50% investment in a joint venture. On 16 August 2016, the Group acquired the remaining 50% of the share capital of Energean Israel Limited for the purpose of investing in the Karish and Tanin licences. The acquisition of the additional 50% did not, however, meet the definition of a business combination as Energean Israel Limited had 0 employees, did not own the Karish and Tanin licences, and the development plan for the offshore fields had not commenced.

Below represents the consideration transferred to acquire the remaining share capital of Energean Israel Limited on 16 August 2016:

Consideration transferred	
Cash paid	41
Fair value of equity interest already held	40
Total consideration transferred	**81**

Assets and liabilities acquired

	Fair value
Trade and other receivables	2
Cash at bank and in hand	88
Trade and other payables	(9)
Net assets acquired	**81**
Cash consideration paid	(41)
Cash and cash equivalents acquired	88
Net cash flow on acquisition	**47**

Acquisition of leasehold rights

On 16 August 2016, Energean Israel Limited entered into a Sale and Purchase Agreement to acquire interests in each of the Tanin and Karish offshore Israel leases issued by the Israel Petroleum Commissioner on 24 December 2015.

Following approval from the Israel Petroleum Commissioner obtained in December 2016, Energean Israel Limited has paid an initial and closing payment of forty million dollars (US$40,000) and has assumed the obligation to pay the remainder of the consideration being a total additional amount of one hundred and eight million and five hundred thousand dollars (US$108,500) in ten equal annual payments and ongoing royalties to the sellers. The additional consideration is due on the earlier of the date on which a final investment decision of Energean Israel Limited has been made or the date on which aggregate expenditures in connection with the leases exceed one hundred and fifty million dollars (US$150,000). The US$108,500 remaining consideration is not recognised in the consolidated financial statements and does not form part of the consideration.

9.1 Details of the joint venture *continued*

In August 2016, Energean E&P Holdings Limited entered into loan agreements with its founding shareholders Oilco Investments, Growthy Holdings and Adobelero Holdings for loans of US$4,750, US$4,750 and US$500 respectively to fund the US$10,000 initial payment pursuant to the sale and purchase agreement for the acquisition of the Karish and Tanin rights. Each of the loans bears interest at 2.0% and had an initial term of 90 days. On 21 December 2016, the Group entered into a subscription agreement with Kerogen Capital Limited ('Kerogen'), a private equity fund manager focused on oil and gas, for the investment of US$50 million to Energean Israel Limited. The initial capital was funded by a US$35 million convertible loan in December 2016 and a further US$5 million loan in the first quarter of 2017, to be converted to equity, together with a further equity investment by Kerogen of US$10 million subject to (i) approval from the Petroleum Commissioner and (ii) the closing of the sale and purchase of the subject interest in accordance with the provisions of the Delek sale and purchase agreement. The loan bears no interest and was repayable by 19 June 2017 in the case that no conversion occurred. The net proceeds received from the issue of the Kerogen convertible loan have been allocated between the financial liability component ($34,167 as of 31 December 2016) and an equity component ($737k as of 31 December 2016). The conversion reserve represents the difference between the fair value of the discounted cash outflows to repay the loan from Kerogen, discounted using the market interest rate, and the total proceeds from the convertible loans of US$40 million.

On 13 June 2017 the Kerogen convertible loan interim facility and founding shareholders' loans were discharged in consideration for the issue of shares in Energean Israel Limited, whereby Kerogen acquired a 50% equity voting interest and a 50% economic interest and the founding shareholders acquired a 50% economic interest in Energean Israel Limited. Energean E&P Holdings Limited retained the remaining 50% of the voting rights of Energean Israel. The shareholders' agreement governing the control and management of Energean Israel Limited specifies that the Group's strategy for the development and operation of the Karish and Tanin fields and the implementation of such strategy are subject to consulting with and obtaining the consent of Kerogen. Accordingly, Energean Israel Limited was classified as a discontinued operation and assets and liabilities held for sale as of 31 December 2016 and ceased to be a subsidiary of the Group on 13 June 2017. Energean Israel Limited was deconsolidated at 13 June 2017.

9.2 Discontinued operations

At 31 December 2016, Energean Israel Limited was presented as a wholly owned subsidiary of Energean E&P Holdings Limited. Based on the Kerogen convertible loan and founding shareholder loans as described above, the Group lost control of Energean Israel Limited on 13 June 2017 and was therefore presented as a discontinued operation in accordance with IFRS 5 Non-Current Assets Held for Sale and Discontinued Operations.

The results of the discontinued operations, which have been included in the consolidated statement of profit or loss, were as follows:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Administration expenses	**(1,112)**	(107)
Exploration and evaluation expenses	**–**	–
Operating loss	**(1,112)**	**(107)**
Finance costs	**(304)**	(126)
Finance income	**11**	–
Income from foreign exchange transactions	**2**	4
Share of results of joint venture	**–**	–
Profit/(loss) from discontinued operations	**(1,403)**	**(229)**

A US$1.5 million gain on disposal of the subsidiary was recognised in other income in profit or loss, based on the difference between the consideration received (nil) and the net liability position of Energean Israel Limited as of 13 June 2017 of US$1.5 million.

Notes to the consolidated financial statements
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9.2 Discontinued operations *continued*

Details of the cash flows of the discontinued operations which are included in the consolidated statement of cash flows are as follows:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Operating activities	**(985)**	193
Investing activities	**(2,715)**	(40,527)
Financing activities	**4,702**	44,854
Net cash from discontinued operation	**1,002**	4,520

The major classes of assets and liabilities comprising the operations classified as held for sale are as follows:

	As at 31 December 2016 (US$ 000)		As at 31 December 2016 (US$ 000)
Intangible assets	40,528		
Other receivables	66	Other payables	423
Cash and cash equivalents	4,609	Borrowings	44,262
Total assets classified as held for sale	**45,203**	**Total liabilities directly associated with assets classified as held for sale**	**44,685**

9.3 Summarised financial information for Energean Israel Limited at 31 December 2017

On 13 June 2017, Energean Israel Limited was deconsolidated and presented as an investment in associate, in which the Group holds no economic interest. Summarised financial information of Energean Israel Limited as at 31 December 2017 is provided below:

	As at 31 December 2017 (US$ 000)
Assets	
Non-current assets	61,622
Cash and cash equivalents	6,791
Other current assets	2,003
Total assets	**70,416**
Liabilities	
Trade and other payables	12,929
Current liabilities	**12,929**
Net assets	**57,487**

	For the year ended 31 December (US$ 000)
Administrative expenses	(2,659)
Finance income	30
Finance costs	(444)
Tax income	704
Net loss	**(2,369)**
Other comprehensive income	–
Total comprehensive income	**(2,369)**

10. Non-controlling interests

10.1 Details of the non-controlling interests

	Voting rights		Share of loss		Accumulated balance	
	2017	2016	**2017**	2016	**2017**	2016
Name of subsidiary	**%**	%	**(US$ 000)**	(US$ 000)	**(US$ 000)**	(US$ 000)
Kavala Oil S.A.	**0.08**	0.08	**(9)**	(1)	**294**	303
Energean International Limited	**–**	–	**–**	–	**224,000**	–
			(9)	**(1)**	**224,294**	**303**

Kavala Oil S.A.

At 31 December 2014, Kavala Oil Employees Association held a 33% interest in Kavala Oil S.A. (please refer also to Note 8.1). In the year ended 31 December 2015 the Group exercised its right to convert 8,659,046 preference shares to common shares resulting in the Group holding 99.92% of the voting rights. The conversion of the preference shares was accounted for as an equity transaction with US$nil cash consideration.

Energean International Limited

On 30 June 2017, as part of the Reorganisation Agreement described in Note 31.4, the loan from Third Point in Energean International Limited (Note 15) was discharged in consideration for the issuance of 224,000 new preference shares in Energean International Limited. The Group derecognised the US$230,761 carrying value of the loan and recognised US$224,000 in equity for the preference shares. The difference of US$6,761 was recognised in other reserves as a capital contribution, as Third Point is an ultimate shareholder of the Group. The US$224,000 equity recognised for the preference shares represents a non-controlling interest in a subsidiary of the Group.

10.2 Dividends

As at 31 December 2017, the declared dividend for the year was US$nil for both Group and Company (2016: US$nil).

11. Inventories

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Raw materials and supplies	**4,956**	4,054
Crude oil	**4,573**	8,703
Total inventories	**9,529**	**12,757**

The Group's raw materials and supplies consumption for the year ended 31 December 2017 was US$1,724 (year ended 31 December 2016: US$2,226, (Note 21). The Group recognised impairment losses in the year ended 31 December 2017 of US$nil (year ended 31 December 2016: US$403) due to obsolete raw materials and supplies.

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12. Trade and other receivables

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Financial items		
Trade receivables	**9,313**	2,143
Receivables from related parties	**184**	3
	9,497	2,146
Non-financial items		
Deposits and prepayments	**9,090**	2,799
Government subsidies	**3,482**	3,077
Advance payment to tax authorities against Mandatory Administrative Appeal (Note 17)	**–**	3,126
Refundable VAT	**2,195**	2,591
Reimbursement from insurance contracts	**420**	–
	24,684	**13,739**

Government subsidies mainly relate to grants from the Greek Public Body for Employment and Social Inclusion ('OAED') to financially support the Kavala Oil S.A. labour cost from manufacturing under the action plan for promoting sustainable employment in underdeveloped or deprived districts of Greece, such as the area of Kavala.

Kavala Oil S.A. participated in this scheme from July 2010 until subsidies ceased to be in force in January 2016. The subsidy balance still outstanding at 31 December 2017 is for the period commencing 1 July 2010 until 31 December 2015.

In December 2015, the Group filed a petition against OAED, and the Greek state itself, seeking the payment of US$2,998 (€2,500). Following several postponements of the hearing initiated by the Greek state, the hearing took place on 14 June 2017 and the final decision is expected to be announced within the year 2018.

The Group is of the view, based on legal advice, that its petition will prevail.

12.1 Neither past due nor impaired balances

Trade balances

The credit quality of trade receivables that are neither past due nor impaired is assessed by reference to historical information about counterparty default rates. The Group for this purpose allocates its neither past due nor impaired trade receivables as follows:

	As at 31 December	
	2017	2016
Trade balances		
Existing customers with no defaults in past	**9,313**	2,143
	9,313	**2,143**

In April 2013 the Group entered into an exclusive agreement for sale of oil products to one client, BP Oil International Ltd, which represents the largest part of trade receivables. Trade receivables are collected within a 30-day period, after the bill of lading date. There was no allowance for impairment of receivables during the year ended 31 December 2017 (year ended 31 December 2016: US$ nil). In accordance with the aforementioned agreement the Group supplies its produced Prinos crude oil to BP Oil International Ltd until the later of a) the expiry of the agreement on 31 July 2021 or b) the delivery of ten million barrels. In December 2017, Moodys published an A1 credit rating for BP plc.

The credit quality of non-trade financial receivables that are neither past due nor impaired is assessed by reference to historical information about counterparty default rates. The Group for this purpose allocates its neither past due nor impaired trade receivables as follows:

	As at 31 December	
	2017	2016
Non-trade balances		
Related parties with no defaults in past	**184**	3
	184	**3**

13. Cash and cash equivalents

13.1 Bank deposits and cash and cash equivalents

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Cash in hand	**16**	27
Bank demand deposits	**8,128**	7,474
Restricted bank deposits	**7,548**	5,476
	15,692	12,977
Less: Non-current deposits	**(1,899)**	(1,116)
Current portion	**13,793**	**11,861**

The effective interest rate on short-term bank deposits was 0.34% for the year ended 31 December 2017 (year ended 31 December 2016: 0.34%).

13.2 Restricted bank deposits

Non-current portion

According to Greek Law, the Group is obligated to plug wells resulting from its own drilling activities. For this purpose, a committee comprising representatives of the three parties involved in the above law; one appointed by the Greek state, a member of the contractor and a third member jointly by the Greek state. The contractor assigns and adjusts the amount of environment rehabilitation provision, which is kept in a restricted account, for the fulfilment of the contractor's obligations. For this purpose, the Group maintains respective cash reserves, which amounted to US$422 as of 31 December 2017 (as of 31 December 2016: US$305).

As of 31 December 2016 an amount of US$193 was maintained in an escrow account for legal and other expenses related to the senior secured loan from its shareholder Third Point (Note 15). This amount was released in August 2017 following the loan conversion to preference shares.

As of 31 December 2017 an amount of US$703 (as of 31 December 2016: US$619) is retained as a bank security pledge for the performance guarantee (amount €587) issued to the Greek Ministry of Environment, Energy & Climate Change in respect of the lease agreement for the Prinos area and in accordance with Law 2779/1999.

As of 31 December 2017 a US$3,598 (€3,000) guarantee from Energean Montenegro Limited was provided in favour of the state of Montenegro, due to expire on 14 October 2020, relating to the Group's concession and mandatory work programme in Montenegro. The guarantee is secured by a US$3,598 (€3,000) cash deposit and according to the submitted work programme for the following year an amount of US$2,824 has been included as the current portion and an amount of US$774 as the non-current portion.

Current portion

As of 31 December 2017 an amount of US$2,680 (as of 31 December 2016: US$4,131), included within current restricted bank deposits, concerns cash reserves retained as a bank security pledge in respect of the bank guarantees issued for the Group's investments in the Ioannina area and corresponds to the current Minimum Expenditure Obligation.

As of 31 December 2017 an amount of $120 (as of 31 December 2016: US$220) concerns bid guarantee provided to the Greek state as part of the tender process for exploration in Western Greece, related to the (then) ongoing bid for the Aitoloakarnania (since awarded) and Arta Preveza blocks. On 25 May 2017 the Group entered into a lease agreement for the Aitoloakarnania block and will be asked to replace the existing US$120 million bid guarantee with the performance minimum work programme guarantee upon ratification. The US$113 bid guarantee for the Arta Preveza block expired on 30 June 2017 as this licence was not awarded to the Group.

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14. Share capital

The Company's initial share capital amounted to £50 (US$65), consisting of an issuance of 50,000 ordinary shares of a nominal value of £1.00 (US$1.3) each on 8 May 2017. On 30 June 2017 the Company effected a 100 for 1 share split resulting in 5,000,000 ordinary shares of a nominal value of £0.01 (US$0.013) each.

On 30 June 2017, the Company also became the parent company of the Group through the acquisition of the full share capital of Energean E&P Holdings Limited, in exchange for 65,643,120 £0.01 (US$0.013) shares in the Company issued to the previous shareholders. As of this date, the Company's share capital increased from £50 (US$65) to £706 (US$917). From that point, in the consolidated financial statements, the share capital became that of Energean Oil & Gas plc. The previously recognised share capital of US$14,904 thousand and share premium of US$125,851 thousand was eliminated with a corresponding positive merger reserve recognised of US$139,903 thousand. The tables below outline the share capital of the Company as at 31 December 2017 and that of Energean E&P Holdings Limited as at 31 December 2016.

	As at 31 December			
	2017 Number of shares	**2017 (US$ 000)**	2016 Number of shares	2016 (US$ 000)
Authorised				
Ordinary shares of €1 each			10,940,520	14,904
Ordinary shares of £0.01 each	**70,643,120**	**917**		

	2017 Number of shares	**2017 (US$ 000)**	2016 Number of shares	2016 (US$ 000)
Issued and fully paid				
On 1 January	**–**	**14,904**	10,940,520	14,904
Group restructuring	**65,643,120**	**(14,052)**	–	–
Issuance of shares and share split	**5,000,000**	**65**	–	–
At 31 December	**70,643,120**	**917**	**10,940,520**	**14,904**

15. Borrowings

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Current borrowings		
Loans from shareholders	**–**	21,130
Current portion of non-current loan	**12,500**	–
	12,500	**21,130**

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Non-current borrowings		
Bank loans	**77,486**	60,253
Other loans	**1,345**	1,182
Loans from shareholders	**–**	193,683
	78,831	**255,118**
Total borrowings	**91,331**	**276,248**

Loans in the consolidated statement of financial position are presented net of amortised cost. Please see Note 31.3 for details of loans from related parties.

15.1 Maturity of non current borrowings

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Between one to two years	**48,345**	–
Between two and five years	**42,986**	255,118
	91,331	**255,118**

Loans from shareholders

In 2014, the Group received a senior secured loan from its shareholder Third Point amounting to US$125,000 in order for the Group to fund the ongoing drilling campaign. The loan was issued at a discount of 90% of face value, had a five year tenor, paid a fixed interest rate of 9.5% until 31 December 2016 and a fixed interest rate of 15.0% for the remaining tenor. In 2015, the loan was amended to increase the amount to US$179,653. On 30 June 2017, as part of the Reorganisation Agreement described in Note 31.4, the loan was discharged in consideration for the issuance of 224,000 new preference shares in Energean International Limited. The Group derecognised the loan and recognised the preference shares as equity. The equity recognised represents a non-controlling interest in a subsidiary of the Group.

Bank loans

EBRD Senior Facility

In May 2016, the Group signed a Senior Facility Agreement with the EBRD, subsequently amended on 12 July 2016, for a US$75 million borrowing base facility to fund the Group's development programme in the Prinos, Prinos North and Epsilon fields. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission.

EBRD Subordinated Facility

In July 2016, the Group signed a EBRD Subordinated Facility Agreement, a subordinated loan agreement with the EBRD, subsequently amended on 8 March 2017, for a US$20 million facility to fund the Group's exploration activities. The facility is subject to an interest rate of 4.9% plus LIBOR01, in addition to fees and commission and an EBITDA participation amount of up to 3.5% of EBITDA (if EBITDA is positive) depending on the amount of the facility drawn.

Other loans

On 26 March 2013, Cyprus Popular Bank Public Company Ltd (Greek branch) which Kavala Oil S.A. transacted with on European Emission Allowances credits (hereby referred to as 'EUAs') during previous years, was sold to Piraeus Bank. Since then and as of the date of these consolidated financial statements, there has not been any written or oral communication with the Bank. Therefore, the Group has decided to further investigate, seeking legal advice on how to deal with this matter. The amount of the liability as of 31 December 2017 is US$1,345 (as of 31 December 2016: US$1,182). These loans are non-interest-bearing and are due on demand.

15.2 Securities pledged

Bank loans

The bank loans are secured as follows:

- First ranking and second ranking share pledge agreement over Energean Oil & Gas S.A. shares
- First ranking and second ranking share pledge agreement over Kavala Oil S.A.'s shares
- First ranking and second ranking contracts pledge and assignment over material agreements related to Prinos drilling
- First ranking and second ranking insurances pledge assignment
- First ranking and second ranking accounts pledge and assignment
- First ranking and second ranking ship mortgage over the *Energean Force* drilling rig

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15.3 The weighted average effective interest rates were as follows:

	As at 31 December	
	2017	2016
Bank loans	**7.16%**	6.96%
Loans from shareholders (Note 31)	**15.42%**	15.39%

16. Net deferred tax (liability)/asset

The deferred taxation movement is as follows:

Deferred tax (liabilities)/assets	Property, plant and equipment (US$ 000)	Deferred expenses and other receivables (US$ 000)	Inventory (US$ 000)	Tax losses (US$ 000)	Staff leaving indemnities (US$ 000)	Accrued expenses and other short-term liabilities (US$ 000)	Total (US$ 000)
At 1 January 2016	**(43,862)**	**6,605**	**244**	**42,817**	**665**	**469**	**6,938**
Increase/(decrease) for the year through:							
profit or loss (Note 29)	(9,319)	4,024	692	15,578	142	400	11,517
other comprehensive income	–				41	–	41
Exchange difference	2,081	(402)	(287)	(2,099)	(66)	(34)	(807)
31 December 2016	**(51,100)**	**10,227**	**649**	**56,296**	**782**	**835**	**17,689**
Increase/(decrease) for the period through:							–
profit or loss (Note 29)	(11,191)	(14,404)	(339)	15,565	(44)	711	(9,702)
other comprehensive income					74		74
Exchange difference	(7,726)	522	85	8,710	111	141	1,842
31 December 2017	**(70,017)**	**(3,656)**	**395**	**80,571**	**923**	**1,687**	**9,903**

At 31 December 2017 the Group has unused tax losses of US$322,063 (as of 31 December 2016: US$225,184) available to offset against future profits. A deferred tax asset has been recognised as of 31 December 2017 in respect of US$80,571 (as of 31 December 2016: US$56,296) of such tax losses.

Tax losses can be utilised to offset taxable profits for a period of time that is dictated by the tax legislation of each country. The above carried forward unused tax losses arise almost exclusively from the Prinos area. Tax losses incurred under the Prinos licence (Law 2779/1999) can be utilised to offset taxable profits up to the termination of Prinos exploitation area.

According to the Ioannina and Katakolo lease agreements the losses incurred in respect of a particular exploitation area prior to the commencement of any exploitable production shall be carried forward without any restrictions for such period. From the commencement of any exploitable production and thereafter, the general income tax provisions shall apply in relation to the carrying forward of losses (currently five years).

The Group expects that there will be sufficient taxable profit in the following years and that deferred tax assets, recognised in the consolidated financial statements of the Group, will be recovered.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries and associates, and interest in joint ventures, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. The Group has no unrecognised deferred tax liabilities for taxable temporary differences arising on its investments in subsidiaries and associates, and interest in joint ventures.

17. Provisions for liabilities

	Decommissioning (US$ 000)	Other provisions (US$ 000)	Total (US$ 000)
At 1 January 2016	**956**	**–**	**956**
New provisions and changes in estimates	1,284	–	1,284
Payments	–	–	–
Unwinding of discount	95	–	95
Currency translation adjustment	(95)	–	(95)
At 31 December 2016	**2,240**	**–**	**2,240**
Current provisions	**–**	**–**	**–**
Non-current provisions	**2,240**	**–**	**2,240**
New provisions and changes in estimates	2,897	12,462	15,359
Payments	–	(3,839)	(3,839)
Unwinding of discount	229	–	229
Currency translation adjustment	322	683	1,005
At 31 December 2017	**5,688**	**9,306**	**14,994**
Current provisions	**–**	**9,306**	**9,306**
Non-current provisions	**5,688**	**–**	**5,688**

* Note that for the purposes of the provision for **decommissioning** discount unwinding is charged in the profit or loss.

17.1 Provision for decommissioning

According to Article 27 of Greece's Law 2779/1999, the Group is obliged to plug only wells drilled pursuant to its own drilling activities. For this purpose, a committee was formed comprised of representatives of the three parties involved in the above law: one appointed by the Greek state, one representing the contractor and a third member jointly chosen by the Greek state and the contractor. The committee assigns and adjust the amount of environment rehabilitation expenditure, which should be kept in restricted accounts, for the fulfilment of the contractor's obligations.

The last meeting of the committee in 2004 defined the amount of obligation as US$310 (€235)' which has been adjusted to US$ at each balance sheet date (as of 31 December 2017: US$281, as of 31 December 2016: US$247). This amount was included in the cost of wells, and an equivalent provision for environmental rehabilitation was established.

In excess of this obligation, the Group recognises an estimated restoration amount for each well drilled in accordance with IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'. The amount recognised as a provision is the present value of the expenditure estimate required to settle the obligation at each balance sheet date, discounted at 6.18% until 2032. The provision is reviewed and adjusted at each balance sheet date as necessary.

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17.2 Legal claims

Tax

During the year ended 31 December 2014, the statutory tax audit of Kavala Oil S.A. for the years 2006-2011 was finalised and the official Tax Report was issued by the Greek tax authorities for tax and transfer pricing penalties amounting to US$6,673 (€5,564). On 22 April 2015, Kavala Oil S.A. has proceeded in executing its Mandatory Administrative Appeal before the Dispute Resolution Directorate of the Greek Ministry of Finance against certain tax assessment notices.

The Group was required to make a prepayment of 50% of the value of the total exposure, thus a total amount of US$3,238 (€2,782) was paid by Kavala Oil S.A. during 2015. In the year ended 31 December 2016 this amount was presented in trade and other receivables (see Note 12) as an advance payment to Greek tax authorities. In 2017, the amount was no longer recorded as an advance payment due to a provision being recognised in full for the tax and transfer pricing penalties, as fully explained later in this note. In the year ended 31 December 2016 the Group had not recorded a provision for the initial tax and transfer pricing penalty.

The appeals were rejected implicitly by the Dispute Resolution Directorate of the Greek Ministry of Finance. Against the decisions of the Dispute Resolution Directorate, Kavala Oil S.A. filed on 8 October 2015 equal number of appeals before the Athens Administrative Court of Appeal. The discussion of these actions took place in February 2017 and the final decision is expected in 2018.

Developments in the tax audit framework in Greece, and specifically the repeal of the 18-month period under which an unqualified tax certificate issued by the statutory auditors to audited companies was considered to be final and the respective tax year to be considered as 'finalised', resulted in a change in attitude of many taxpayers during the period ended 31 December 2017, in respect of the approach followed with unaudited tax years.

In addition, the five-year statute of limitation for the unaudited year of 2012 ends by the end of 2018. As of 31 December 2017, the Company has not received a tax audit request for the most recent non-prescribed unaudited year, which in the case of Kavala Oil S.A. is 2012.

Kavala Oil S.A.'s court appeal against the transfer pricing penalties as well as the adjustment of the tax losses of the company is still pending and if a tax audit request is submitted to the company before the issuance of the court decision, it is likely that the tax auditors will follow the same approach as their predecessors and adjust the tax losses of the company accordingly.

Following the developments that took place in this period, the Company recognised a provision for its unaudited tax years 2012-2016 of US$4,155. This takes into consideration the outcome of the tax audit of the Company's transfer pricing policies finalised for fiscal year 2011. This amount corresponds to a corporate income tax amount of US$2,303 (Note 29) plus penalties and interest of US$1,851 (Note 29).

The Company has also recorded a provision of US$6,935 for the fiscal years 2006-2011 which it is currently appealing. The amount differs from the initial assessment in the Tax Report due to additional interest and penalties accruing during the appeals process. The decision of the court is expected to be issued no sooner than the first half of 2018, if the decision is not in favour of the Company, this amount is payable in two equal monthly instalments. In such case, the Group's intention is to submit an appeal at the higher level court (Council of State). An amount of US$3,839 of the US$6,935 has been already paid as prepayment in order to enable the Company to submit an administrative appeal. The total provision amounts for transfer pricing penalties of US$6,935 are included in other expenses (Note 25) and provision amounts for taxation expenses and income tax penalties of US$4,155 in taxation (expense)/income (Note 29). The total payable amount under the above provision, out of already paid amount of US$3,839, is included in current liabilities under 'Provisions for liabilities' in the consolidated statement of financial position, since the Company estimates the final decision will not be announced until 30 June 2018.

Other

The Plaintiff, a State Company entrusted with the Operation of the Electricity Transmission System in Greece ('ADMIE'), commenced a claim against Kavala Oil S.A. in November 2014 seeking payments of €376 as utilities charges for the time period 2009-2011. ADMIE alleges that Kavala Oil, as owner of a power plant within the onshore facilities in Kavala and as the operator of this power plant exclusively for industrial own use, is subject to these charges – as any ordinary energy consumer would be under Greek law (Greek Energy Acts Nos. 2773/1999, 4067/2012 & 4001/2011) and the regulation of electricity distribution and transmission charges, approved by the Greek Energy Regulatory Commission ('RAE') in 2008 and 2009 ('Charge Regulation 2008', 'Charge Regulation 2009', 'CHR 2008 & 2009').

17.2 Legal claims *continued*

It must be noted that RAES' CHR 2008 & 2009 have been contested (by social organisations and other entities of consumers) before the Greek Supreme Administrative Court (Council of State) and due to constitutional illegality annulled. Thus, the abovementioned Act No. 4001/2011 reintroduced provisions similar to those of RAE's CHR 2008 & 2009.

By the decision of the Court of Appeal No. 91/2017 the Group is ordered to pay €376 (plus interest from the claim filing date, 30 December 2014). Thus the Group proceed with a provision amount US$405 which is included in 'Other expenses'. Effective December 2017, the Group started the repayment of the awarded amount in ten equal instalments of €49.7 each, bearing no interest, of which the first was paid in November 2017 and the tenth and last on shall be paid in August 2018. The Group reserves all rights against ADMIE based on the outcome of the case brought before the Supreme Court.

Allocated as:

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Provisions to be used after more than 12 months	**8,976**	4,665
Provisions to be used within 12 months	**8,021**	–
	16,997	4,665

18. Retirement benefits obligation

The Group provides retirement benefits in the form of lump sum amounts based on an unfunded fixed benefit retirement plan to its employees. The Group's policy is to carry out an independent actuarial valuation every three years of the liabilities with regard to the retirement benefit plan.

According to the plan, a certain percentage of the current salary is converted into a pension component each year until retirement. Pensions under this scheme are paid out when a beneficiary has reached the age of 65. Eligible employees are required to contribute 2% of their pensionable salary. The pension payments are also linked to the Greek consumer price index (CPI) in euros.

In accordance with the provisions of Greek labour law, employees are entitled to compensation in case of dismissal or retirement. The amount of compensation varies depending on salary, years of service and the manner of termination (dismissal or retirement). Employees who resign are not entitled to compensation. The compensation payable in case of retirement is equal to 40% of the compensation which would be payable in case of unjustified dismissal. These plans are not funded and are defined benefit plans in accordance with IAS 19. The Greek subsidiaries charge the accrued benefits in each period with a corresponding increase in the relative actuarial liability. The payments made to retirees in every period are charged against this liability. The liabilities of the Group arising from the obligation to pay termination indemnities are determined through actuarial studies, conducted by independent actuaries.

18.1 Provision for retirement benefits

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Defined benefit obligation	**3,288**	2,425
Provision for retirement benefits recognised	**3,288**	**2,425**
Allocated as:		
Non-current portion	**3,288**	2,425
	3,288	**2,425**

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18.2 Defined benefit obligation

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
At 1 January	**2,425**	2,115
Current service cost	**296**	253
Interest cost	**43**	39
Extra payments or expenses	**34**	43
Actuarial losses – from changes in financial assumptions	**258**	148
Benefits paid	**(86)**	(89)
Exchange differences	**318**	(84)
Total	**3,288**	**2,425**

The average duration of the defined benefit obligation at 31 December 2017 is 25 years (year ended 31 December 2016: 25 years).
As of 31 December 2017, based on historical data, the Group expects benefits of approximately US$70 to be paid for 2018.

18.3 Impact on total comprehensive income

Amounts recognised in profit or loss:

	For the year ended 31 December	
	2017	2016
Current service cost	**210**	253
Interest cost	**43**	41
Extra payments or expenses/(income)	**34**	43
Total expense	**287**	**337**
Amounts recognised in other comprehensive income:		
Actuarial losses – from changes in financial assumptions	**258**	148
Total remeasurements	**545**	**485**

18.4 Actuarial assumptions and risks

The most recent actuarial valuation was made as at 31 December 2017 and was based on the following key assumptions:

	As at 31 December	
	2017	2016
Discount rate	**1.50%**	1.50%
Expected rate of salary increases	**3.59%**	3.59%
Average life expectancy	**24.57 years**	24.57 years
Inflation rate	**1.75%**	**1.75%**

Sensitivity analysis

The sensitivity analysis below shows the impact on the defined benefit obligation of changing each assumption while not changing all other assumptions. This analysis may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Effect of +0.5% change in defined benefit obligation		
Discount rate	**+9.0%**	+9.0%
Expected rate of salary increases	**+14.0%**	+14.0%
Effect of -0.5% change in defined benefit obligation		
Discount rate	**-9.0%**	-9.0%
Expected rate of salary increases	**-14.0%**	-14.0%

18.4 Actuarial assumptions and risks *continued*

The amounts presented reflect the percentage increase/(decrease) in the given assumption that is required to impact the defined benefit obligation by +/-0.5%, while holding all other assumptions constant.

The plan exposes the Group to actuarial risks such as interest rate risk, longevity changes and inflation risk.

Interest rate risk

The present value of the defined benefit liability is calculated using a discount rate determined by reference to market yields of high-quality corporate bonds. The estimated term of the bonds is consistent with the estimated term of the defined benefit obligation and it is denominated in euros. A decrease in market yield on high-quality corporate bonds will increase the Group's defined benefit liability.

Longevity of members

The Group is required to provide benefits for life for the members of the plan. Any increase in the life expectancy of the members will increase the defined benefit liability.

Inflation risk

A significant proportion of the defined benefit liability is linked to inflation. An increase in the inflation rate will increase the Group's defined benefit liability.

19. Trade and other payables

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Financial items		
Trade payables	**47,965**	18,976
Accrued expenses	**9,664**	5,424
Other creditors	**2,281**	834
Other finance costs accrued	**2,071**	970
Staff costs accrued	**1,461**	1,313
	63,442	**26,547**
Non-financial items		
Social insurance and other taxes	**5,631**	5,272
Total	**5,631**	5,272
Less non-current payables	**(2,544)**	(2,737)
Current portion	**66,528**	**29,082**

The non-current payables include US$2,544 related to the non-current portion of the social security's liabilities.

Finance cost accrued includes accrued interest expenses related to Group's borrowings.

20. Revenue

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Crude oil sales	**55,113**	38,843
Sales of scrap	**17**	25
Rendering of services	**1,877**	–
Petroleum products sales	**1,025**	1,389
Gain/(loss) on forward transactions	**(280)**	(533)
Total sales revenue	**57,752**	**39,724**

For the year ended 31 December 2017, the amount of US$1,877 included in 'Revenue from rendering of services' related to services provided by Energean International Limited under the 19 December 2016 Services Agreement to Energean Israel Limited (please refer to Note 31).

Notes to the consolidated financial statements
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21. Cost of sales

Cost of oil sales	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Opening inventory	9,230	4,074
Closing inventory	(4,227)	(9,044)
	5,003	(4,970)
Direct costs		
Depreciation	17,640	21,218
Staff costs (Note 27)	12,598	11,609
Electricity and fuel	5,767	6,014
Processing materials	1,724	2,226
Machinery repairs and maintenance	2,452	2,046
Insurance	1,258	998
Subcontracted work	915	670
Sundry expenses	372	410
Royalties	176	330
	42,902	45,521
Total cost of oil sales	47,905	40,551

Cost of services	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Staff costs (Note 27)	600	–
Other professional fees	106	–
Other expenses	37	–
Total cost of services	743	–
Total cost of sales	48,648	40,551

22. Exploration and evaluation expenses

	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Staff costs (Note 27)	244	1,133
Impairment of exploration and evaluation costs and property, plant and equipment	8,007	–
Provision for bank guarantee related to exploration licence (Note 33.2)	1,285	
Third-party fees	430	–
Total	9,966	1,133

23. Administration expenses

	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Staff costs (Note 27)	3,048	1,989
Telecommunication and other office expenses	432	153
Operating leases	395	251
Licences and taxes	56	29
Repairs and maintenance	92	1
Audit fees for statutory audit	253	92
Auditors' fees for other assurance services	120	69
Auditors' fees for tax services	45	21
Accounting fees	33	12
Legal fees	274	330
Other professional fees	297	301
Overseas travel	319	203
Corporate social responsibility	22	25
Amortisation of intangibles	200	144
Depreciation of property, plant and equipment	168	137
Other administration expenses	237	377
Total general and administrative expenses	5,991	4,134

The Company has a policy on the provision of non-audit services by the auditor which is aimed at ensuring their continued independence. The use of the external auditor for services relating to accounting systems or financial statement preparations is not permitted.

Auditors' fees for other assurance services relate to interim period audit services from the Group's previous auditors. Auditors' fees for tax services relate to services from Group's statutory auditors to the Greek entities regarding the Tax Compliance Certificate.

24. Selling and distribution expenses

	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Staff costs (Note 27)	181	163
Advertising	228	131
Sundry expenses	36	42
Total selling expenses	445	336

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25. Other expenses

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Other taxes	**40**	7
Other non-operating expenses	**811**	754
Provision for litigation expenses	**6,935**	–
Provision for bad debts	**401**	–
Loss from sales of property, plant and equipment		1,577
Impairment loss on property, plant and equipment	**–**	1,947
Impairment loss on inventory	**–**	403
Total other expenses	**8,187**	**4,688**

Provision for litigation expenses amounting to US$6,935 relates to transfer pricing penalties (please refer to Note 17.2).

26. Other income

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Reversal of prior period provision	**235**	248
Profit from disposal of subsidiary	**1,540**	–
Other income	**14**	–
	1,789	**248**

Reversal of prior period provision concerns mainly reversals of prior period provisions related to employee vacation leave and other, as well as previous period energy cost credits.

27. Staff costs

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Wages and salaries	**17,274**	13,950
Directors' remuneration (Note 31)	**2,089**	1,720
Social insurance costs and other funds	**4,418**	3,547
Other staff costs	**1,059**	1,167
Expenses related to defined benefit plan (Note 18)	**304**	296
Payroll subsidies	**(91)**	(13)
Payroll cost capitalised in oil and gas assets and exploration and evaluation costs	**(8,358)**	(5,773)
Total payroll cost	**16,695**	**14,894**
Staff cost included in:		
Cost of sales	**13,198**	11,609
Administration expenses	**3,048**	1,989
Exploration and evaluation costs	**244**	1,133
Selling and distribution expenses	**181**	163
Other	**24**	
Payroll cost expensed	**16,695**	**14,894**
Average number of employees (excluding executive Directors):	**386**	**379**

28. Finance income and costs

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Finance income		
Interest income	**14**	327
	14	**327**
Finance costs:		
Interest-bearing loans and borrowings	**6,151**	2,407
Amortisation of related parties' loan interest and issuance fees (Note 31)	**16,070**	28,652
Capitalisation of borrowing costs to assets	**(1,258)**	(3,992)
Unwinding of discount on provisions	**203**	93
Interest expenses of pension benefit obligation	**43**	39
Fees for Group funding purposes	**499**	610
Other bank charges	**1,232**	1,502
Total finance costs	**22,940**	**29,311**
Net finance costs	**(22,926)**	**(28,984)**

Finance income represents interest income earned on cash at banks and on short-term deposits.

29. Taxation (expense)/income

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Corporation tax – current year	**(204)**	–
Corporation tax – prior years (Note 17.2)	**(4,155)**	–
Deferred tax (Note 16)	**(9,702)**	11,517
Total taxation (expense)/income	**(14,061)**	**11,517**

Taxation Cyprus

The Group is subject to corporation tax on its taxable profits at the rate of 12.5%. Any capital gains are taxed at the rate of 20%. Under certain conditions interest is subject either to corporation tax or to defence contribution. The relevant corporation tax rate for the year is 12.5% and the defence contribution rate is 30%.

Companies in Cyprus which do not distribute 70% of their profits after tax, as defined by the relevant tax law, within two years after the end of the relevant tax year, will be deemed to have distributed as dividends 70% of these profits. Special contribution for defence at 17% will be payable on such deemed dividends to the extent that the shareholders (companies and individuals) are both tax resident and also domiciled in Cyprus. The amount of deemed distribution is reduced by any actual dividends paid out of the profits of the relevant year at any time. This special contribution for defence is payable for the account of the shareholders. Given the current tax position of the Group's companies in Cyprus, these deemed distribution rules are not applicable.

Taxation Greece

The nominal tax rates applicable to Energean are exclusively governed per each contract area by the provisions of the lease agreements ratified by Laws 2779/1999 (Prinos), 4298/2014 (Katakolo) and 4300/2014 (Ioannina). The applicable tax rate according to the aforementioned agreements for the years ended 31 December 2017 and 2016 is 25%.

On 12 July 2017 a tax audit order was issued by the Greek tax authorities in respect of FY12 for Energean Oil & Gas S.A. and the request for information commenced on 15 January 2018. For FY12, Energean Oil & Gas S.A, was audited by Grant Thornton, in accordance with Article 82 of Greece's Law 2238/1994 and received an unqualified tax certificate. On this basis should any tax liabilities arise from the audit, they are not expected to have a material effect on the consolidated financial statements.

The nominal tax rate of Kavala Oil S.A. for the years ended 31 December 2017 and 2016 is 29%.

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29. Taxation (expense)/income *continued*

The tax on the Group's results before tax differs from the theoretical amount that would arise using the applicable tax rates as follows:

Reconciliation to Group tax charge:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Profit/(loss) before tax	**24,004**	**(50,126)**
Tax calculated at the applicable tax rates	**(6,001)**	12,532
Impact of different tax rates	**109**	(12)
Reassessment of recognised deferred tax asset in the current period	**(549)**	–
Permanent differences	**(3,258)**	(1,076)
Other adjustments	**12**	73
Prior year tax	**(4,155)**	–
Taxation (charge)/income	**(14,061)**	**11,517**

30. Earnings per share

The earnings per share has been calculated by dividing the net profit or loss for the period by the weighted average number of shares outstanding during the year ended 31 December 2017 and 2016. There were no potentially dilutive instruments outstanding during any period, therefore the basic and diluted earnings per common share were equal.

In accordance with IAS 33 'Earnings Per Share', the comparative weighted average number of shares was restated to apply the number of shares which arose from the Group restructuring described in Note 14.

From continuing and discontinued operations

The calculation of basic and diluted earnings/(loss) per share is based on the following data:

Profit/(loss)

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Profit/(loss) from continuing operations attributable to owners of the parent	**11,355**	(38,379)
Net results from discontinued operations	**(1,403)**	(229)

Number of shares

	For the year ended 31 December	
	2017	2016
Weighted average number of ordinary shares in issue during the year (prior to the Group restructure)	**10,940,520**	10,940,520
Weighted average number of ordinary shares in issue during the year (post the Group restructure)	**70,643,120**	70,643,120

From continuing operations

	For the year ended 31 December	
	Basic and diluted 2017	Basic and diluted 2016
Total income/(loss) from continuing operation per share (prior to the Group restructure)	**$1.04**	($3.51)
Total income/(loss) from continuing operation per share (post the Group restructure)	**$0.14**	($0.54)

30. Earnings per share *continued*

From discontinued operations

	For the year ended 31 December	
	Basic and diluted 2017	Basic and diluted 2016
Total income/(loss) from discontinued operations per share (prior to the Group restructure)	**($0.13)**	($0.02)
Total income/(loss) from discontinued operations per share (post the Group restructure)	**($0.02)**	($0.00)

30.1 Dividends paid and proposed

As at 31 December 2017, the dividend for the year was US$nil for both Group and Company (2016: US$nil).

31. Related parties

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note. Transactions between the Group with its associates and other related parties are disclosed below.

The Group is not controlled by any legal entity or physical person, including its shareholders.

Adobelero Holdings Co Ltd. is a beneficially owned holding company controlled by Panos Benos, the CFO of the Group. Growthy Holdings Co Ltd is a beneficially owned holding company controlled by Mathios Rigas, the CEO of the Group. Oil Co Investments Limited is beneficially owned and controlled by Efstathios Topouzoglou, a non-executive Director of the Group. The nature of the Group's transactions with the above related parties is mainly financing activities.

Seven Maritime Company ('Seven Marine') is a related party company controlled by Efstathios Topouzoglou. Seven Marine owns the offshore supply ships *Valiant Energy* and *Energean Wave* which support the Group's investment programme in northern Greece.

Third Point Hellenic Recovery (Lux) S.À.R.L. is a US-based institutional investor that has historically supported the Group through debt funding and remains one of the Group's largest shareholders.

31.1 Trading transactions

During the year, Group companies entered into the following transactions with related parties who are not members of the Group:

Sale of assets

In May 2016, the subsidiary Energean Oil & Gas S.A. sold its Greek flagged supply vessel named *Valiant Energy* for the amount of US$2,698. The net book value of the vessel at the time of the sale was US$4,275 and therefore a loss of US$1,577 was recognised in 2016. Later, in May 2016, the subsidiary leased back the vessel through a time charter agreement (an operating lease agreement) with Seven Marine.

Sale of technical services

A Technical Services Agreement dated 19 December 2016 was signed between Energean International Limited and Energean Israel Limited for the provision of project advisory, technical and commercial consulting services between the two companies.

Services are compensated based on daily rates negotiated on an arm's-length basis.

		For the year ended 31 December	
	Nature of transactions	**2017 (US$ 000)**	2016 (US$ 000)
Other related party (under common control)	Sale of vessel	**–**	2,911
Energean Israel Ltd	Technical services	**1,498**	–
		1,498	**2,911**

Notes to the consolidated financial statements
continued

31.1 Trading transactions *continued*

Purchase of goods or services

	Nature of transactions	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Key management	Financial advisory services	–	512
Other related party	Property lease	67	70
Other related party 'Seven Marine'	Vessel leasing	6,430	2,482
Third Point Hellenic Recovery Fund L.P.	Finance cost	16,070	28,652
Growthy Holdings CO	Finance cost	43	35
Oilco Investments Limited	Finance cost	43	35
Adobelero Holdings CO	Finance cost	4	4
		22,657	31,790

During year 2016 the Group received financial advisory services for the Group's funding purposes from a company under the control of one of its executive Directors. The services were rendered at cost plus a mark-up. Property lease to other related party includes rental fees of a flat in London at a monthly rent of £4,300. The flat is used as a company flat for Energean's staff and consultants during London meetings. The flat is beneficially owned by executive director wife. The following amounts were outstanding at each balance sheet date:

Payables to related parties

	Nature of balance	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Energean Israel Limited	Technical services	1,477	–
Other related party 'Seven Marine'	Vessel leasing	2,562	214
Key management	Financial advisory services	–	310
		4,039	524

Related party balances are included within trade payables.

Receivables from related parties

	Nature of balance	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Other related parties 'Seven Marine'	Sale and leasing of vessel	–	1,747
		–	1,747

Related party balances are included within trade and other receivables. The amounts outstanding are unsecured and will be settled in cash. No guarantees have been given or received. No provisions have been made for doubtful debts in respect of the amounts owed by related parties.

31.2 Key management compensation

Key management personnel are those persons who have the authority and responsibility for planning, directing and controlling the activities of the Group. The definition of key management personnel includes Directors (both executive and non-executive) and other executives from the management team with significant authority and responsibility for planning, directing and controlling the entity's activities. Key management personnel compensation comprises the following:

Directors' remuneration

	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Salary and fees	1,771	1,720
Annual bonus	1,657	–
Total	**3,428**	**1,720**

31.2 Key management compensation *continued*

The above amounts for remuneration includes the following in respect of the highest paid director:

	For the year ended 31 December 2017 (US$ 000)	2016 (US$ 000)
Salary and fees	776	1,173
Annual bonus	1,037	–
Total	**1,813**	**1,173**

The directors did not receive any other remuneration.

31.3 Loans from related parties (Note 15)

	Nature of balance	As at 31 December 2017 (US$ 000)	2016 (US$ 000)
Third Point Hellenic Recovery Fund L.P. (Shareholder – interest 44.61%) – Note 15	Principal	–	179,653
Third Point Hellenic Recovery Fund L.P. (Shareholder – interest 44.61%) – Note 15	Accrued interest, net of discount	–	35,160
Growthy Holdings CO Limited (Shareholder – interest 24.60%) – Note 9	Principal	–	4,750
Growthy Holdings CO Limited (Shareholder – interest 24.60%) – Note 9	Accrued interest	–	35
Oilco Investments Limited (Shareholder – interest 24.60%) Note 9	Principal	–	4,750
Oilco Investments Limited (Shareholder – interest 24.60%) Note 9	Accrued interest	–	35
Adobelero Holdings CO Limited (Shareholder – interest 3.75%) Note 9	Principal	–	500
Adobelero Holdings CO Limited (Shareholder – interest 3.75%) Note 9	Accrued interest	–	4
		–	224,887

31.4 Reorganisation

On 30 June 2017 the Group entered into a Reorganisation Agreement which was subsequently amended by the 'Supplementary Agreement' dated 31 October 2017. The Reorganisation Agreement is between the Company and the existing shareholders of Energean E&P Holdings ('the Existing Shareholders'), Energean E&P Holdings, Energean Israel and Energean International. Under the Reorganisation Agreement, the Company became the holding company of the Group (see Note 1.1) and the senior secured loan from Third Point and certain other parties was discharged in exchange for US$224 million preference shares in Energean International Limited.

The preference shares in Energean International Limited have no voting rights. Rights to future capital and distributions comprise the right to a return of capital of $224 million upon winding up of Energean Israel Limited and, as clarified in the Supplementary Agreement dated 31 October, priority over distributions to the Company's ordinary shareholders up to an amount of $224 million.

Under the Reorganisation Agreement dated 30 June 2017 and the subsequent Supplementary Agreement dated 31 October 2017, the Group also made the following commitments:

- Under the Reorganisation Agreement dated 30 June 2017, in the event of an Exit transaction as defined in the Reorganisation Agreement, the Group committed to acquire the preference shares in Energean Israel Limited. Consideration would be in the form of ordinary shares of the Company to the value of $224 million in the event of a Sale transaction or $240 million in the case of an IPO. Under the Reorganisation Agreement, each of Third Point and the Founders may at any time propose an Exit Event at which time each of the other parties to this Agreement shall: (i) give such co-operation and assistance as such Parties may reasonably request; and (ii) use all reasonable endeavours to procure that such Exit Event is achieved in accordance with such proposal, and therefore the contingent settlement provision of the preference shares represented a financial liability at 30 June 2017, initially recognised at its fair value and subsequently carried at amortised cost (see Note 34.2 for the impact on the consolidated financial statements). Under the Supplementary Agreement dated 31 October 2017, the process for implementation of an Exit Event (whether by reference to an IPO or Sale) requires the consent of each of Third Point, the Founders and the Company; therefore the liability recognised was extinguished on 31 October 2017 with no impact on profit or loss.
- Under the Reorganisation Agreement dated 30 June 2017, in the event of an Exit transaction as defined in the Reorganisation Agreement, the Group committed to acquire the Founders' 50% interests in the B shares of Energean Israel Limited which represent 50% of the beneficial ownership of Energean Israel. Taken together with the Group's A shares of Energean Israel Limited (see Note 9), this would result in Energean Israel becoming a 50% joint venture investee of the Group. Consideration would be in the form of ordinary shares of the Company to the value of $50 million in the event of a Sale transaction or $150 million in the case of an IPO.

Notes to the consolidated financial statements
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31.4 Reorganisation *continued*

- Under the Reorganisation Agreement, the Group was contractually obliged to pursue an Exit transaction, and therefore the contingent share purchase represented a derivative financial instrument at 30 June 2017, carried at fair value through profit and loss (see Note 34.2). Pursuant to the terms of the Supplementary Agreement the Company agreed to acquire the Energean Israel Limited Class B Shares from its founder shareholders upon the occurrence of:

  (i) a Sale for US$10 million in cash (rather than for the issue of New Shares as contemplated by the Reorganisation Agreement); or
  (ii) an IPO for US$10 million in cash (rather than for the issue of New Shares as contemplated by the Reorganisation Agreement).

The impact of the Supplementary Agreement on the derivative financial instrument was recognised as a credit to equity. In March 2018 the Company completed the admission of its shares to the Premium Segment of the London Stock Exchange.

32. Legal cases and other contingent liabilities

32.1 Other contingent liabilities

The Group had no material contingent liabilities as of 31 December 2017 and 2016.

33. Commitments and contingencies

33.1 Operating lease commitments

The non-cancellable operating lease agreements entered by the Group relate mainly to:

- Lease of supply vessel *Valiant Energy*;
- Lease of supply vessel *Energean Wave*;
- Office rentals; and
- Vehicle leases.

The total operating lease expenses for the year ended 31 December 2017 amounted to US$395 (year ended 31 December 2016: US$251).

The future aggregate minimum lease payments under non-cancellable operating leases are as follows:

	For the year ended 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Within one year	**6,373**	6,546
Between one and five years	**6,798**	5,904
After five years	**165**	219
	13,336	**12,669**

33.2 Performance guarantees

Energean Israel Limited, on 25 December 2016, submitted to the Petroleum Commissioner two irrevocable bank guarantees issued by HSBC of US$10 million each, for each of the Karish and Tanin leases, to secure compliance with the leases and related liabilities. The guarantees replace the respective guarantees in the amount of US$7.5 million each given by the previous leaseholders Noble, Delek, and Avner.

The Group has issued a Letter of Guarantee of US$6,000 to beneficiary Ganoub El Wadi Holding Petroleum ('GANOPE'), which is the Egyptian Oil Commissioning Authority, in respect of the capital and financial commitments of its related entity, Energean International Limited, in the area of West Kom Ombo. As of 31 December 2017, the US$6,000 guarantee has been reduced to US$2,225 and is now due to expire on 2 May 2018. The Group relinquished the area in October 2017 and the respective bank guarantee was further reduced in April 2018 to the amount of US$1,285. The Group in the year ended 31 December 2017, recognised a provision of US$1,285 for the remaining amount of the financial commitment (note 22).

The Group provided a performance guarantee for the amount of US$704 (€587) issued to the Greek Ministry of Environment, Energy and Climate Change in respect of the contract with the Greek State for exploitation in the Prinos area. See Note 13.2.

33.2 Performance guarantees *continued*

In relation to the investment in the areas of Ioannina and Katakolo, Energean Oil & Gas S.A. and its partners proceeded to provide bank guarantees in favour of the Greek Ministry of Environment & Energy for total amounts of US$8,600 (€7,900), and US$751 (€690), for each area respectively. The purpose of these guarantees is the security of the minimum expenditure obligation per area, by Energean Oil & Gas S.A. and its partners, as this derives from the provisions of the respective lease agreements.

As of 31 December 2016, the US$8,600 (€7,900) performance bank guarantee related to Ioannina block was reduced to US$6,507 (€6,173) while as of 31 December 2017 it has been further reduced to US$6,666 (€5,558), and will be further reduced from time to time to represent the remaining minimum expenditure obligations. For the security of any bank claim on the aforementioned guarantees, Energean Oil & Gas S.A. proceeded to restricting an amount of US$2,680 (€2,235), which corresponds to its 40% participating interest as described in Note 13.2.

The performance bank guarantee of US$379 (€360) related to Katakolo block has already expired, since Energean Oil & Gas S.A. has executed the committed minimum expenditure.

A €3.0 million guarantee from Energean Montenegro Limited in favour of the state of Montenegro, due to expire on 14 October 2020, relates to the Group's concession and mandatory work programme in Montenegro. The guarantee is secured by a €3.0 million cash deposit (see Note 13.2).

33.3 Contingent consideration

Energean Israel Limited has an obligation to pay a total additional amount of one hundred and eight million and five hundred thousand dollars (US$108,500) in ten equal annual payments for the acquisition of the Tanin and Karish offshore Israel leases as described in Note 9.1. This additional payment represents contingent consideration that is not recognised within the consolidated financial statements. The contingent consideration is due on the earlier of the date on which a final investment decision of Energean Israel Limited has been made or the date on which the aggregate expenditures in connection with the Israeli leases exceed US$150,000.

34. Financial assets and liabilities

34.1. Carrying amount

The carrying amount of each class of financial assets and liabilities included in the consolidated statement of financial position is as follows:

	Notes	As at 31 December	
		2017 (US$ 000)	2016 (US$ 000)
Financial assets			
Measured at amortised cost:			
Cash and cash equivalents and bank deposits	13, 9	**15,692**	17,586
Trade and other receivables	12	**9,497**	2,146
Measured at fair value through profit or loss:			
Derivative asset		**93,292**	–
		118,481	**19,732**
Financial liabilities at amortised cost			
Borrowings	15, 9	**91,331**	310,415
Trade and other payables	19	**63,442**	26,547
		154,773	**336,962**

34.2. Fair value measurements

The information set out below provides information about how the Group determines fair values of various financial assets and liabilities.

The fair values of the Group's financial assets and liabilities measured at amortised cost approximate to their carrying amounts at the reporting date. The carrying value less any estimated credit adjustments for financial assets and financial liabilities with a maturity of less than one year are assumed to approximate their fair values due to their short term-nature.

Notes to the consolidated financial statements
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34.2. Fair value measurements *continued*

The Group has only one material financial asset measured at fair value at 31 December 2017 which relates to the Energean Israel B shares. As part of the reorganisation, the Group on 30 June 2017 committed to acquire the 50% of the class B shares of Energean Israel Limited in an Exit Event (See Note 31.4).

The valuation technique used multiplies the estimated likelihood of an Exit (being an IPO or a Sale) by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares to be acquired under the commitment. The key input assumptions used in the fair value measurement calculation are the estimated likelihood of an IPO event and value of the B shares. An Exit in the form of a Sale is considered to be of negligible likelihood. The other significant inputs are the transaction prices applicable in an Exit Event, which are contractually agreed amounts, and the discount rate assumption used in the calculation which was 11.5%. The fair value of the derivative asset is a Level 3 fair value measurement in the fair value measurement hierarchy, because the valuation relies significantly on input assumptions that are unobservable.

On remeasurement on 31 December 2017, the value of the B shares was estimated based on the price negotiated at a similar time with a third party for another tranche of the B shares in a separate transaction. The likelihood of a future IPO occurring was estimated as of 31 December 2017 to be 50%, having regard to the considerable progress made to prepare for an IPO as of that date, but also to the fact that there were a number of significant steps not wholly under the control of the Group that remained to be achieved, and the inherent uncertainty in achieving any IPO due to capital market conditions.

The change in fair value of US$25,786 between 30 June 2017 and 31 December 2017 is included in 'Gain on derivative' in the consolidated statement of profit or loss as it is due to changes in measurement assumptions.

Also on 31 October 2017, under the Supplementary Agreement (see Note 31.4) the consideration payable to acquire the B shares in the event of an IPO was reduced from US$150 million to US$10 million. The resulting increase in the value of the derivative asset of US$67,506 (after applying the 50% IPO likelihood assumption and other discounting effects) is recorded in the consolidated statement of changes in equity as the Supplementary Agreement is a transaction with owners, giving the derivative asset a closing value as of 31 October 2017 of US$91,615. As of 31 December 2017 the derivative asset was further increased to US$93,292 due to unwinding of the discount applied at the recognition, resulted in additional gain of US$1,677 recorded in profit or loss.

If the probability of an IPO increased to 100%, whilst the probability of a sale was 0% and the discount rate was held constant, the fair value of the derivative asset to purchase Energean Israel Class B shares at 31 December 2017 would increase by US$93,292.

If the discount rate increased from 11.5% to 20%, whilst the probability of an IPO and probability of a sale were held constant, the fair value of the derivative asset to purchase Energean Israel Class B Shares at 31 December 2017 would decrease by US$1,135.

Upon recognition, the derivative was the only instrument in the Level 3 category of the fair value hierarchy. There were no transfers in or out of this category in the period, and the only movement in the category relates to the increase in fair value of the derivative.

The fair value hierarchy of financial assets and financial liabilities that are not measured at fair value (but fair value disclosure is required) is as follows:

	Fair value hierarchy as at 31 December 2017			
	Level 1 (US$ 000)	Level 2 (US$ 000)	Level 3 (US$ 000)	Total (US$ 000)
Financial assets				
Trade and other receivables	–	9,497	–	9,497
Cash and cash equivalents and bank deposits	15,692	–	–	15,692
Total	**15,692**	**9,497**	**–**	**25,189**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	–	91,331	–	91,331
Trade and other payables	–	63,442	–	63,442
Total	**–**	**154,773**	**–**	**154,773**

34.2. Fair value measurements *continued*

	Fair value hierarchy as at 31 December 2016			
	Level 1 (US$ 000)	Level 2 (US$ 000)	Level 3 (US$ 000)	Total (US$ 000)
Financial assets				
Trade and other receivables	–	2,146	–	2,146
Cash and cash equivalents and bank deposits	17,586	–	–	17,586
Total	**17,586**	**2,146**	**–**	**19,732**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings	–	276,248	–	276,248
Convertible loan notes	–	34,167	–	34,167
Trade and other payables	–	26,547	–	26,547
Total	**–**	**336,962**	**–**	**336,962**

There were no transfers between Level 1, Level 2 and Level 3 fair value measurements during the year.

35. Financial risk management

The Group's Treasury function provides services to the business and monitors and manages the financial risks relating to the operations of the Group, through internal reporting which analyses exposures by degree and magnitude of risk. These risks include market risk (interest rate risk, credit risk, foreign exchange risk, liquidity risk).

The Treasury function reports monthly to the Board of Directors to monitor risks and policies implemented to manage risk exposures.

35.1 Interest rate risk

The Group's policy is to minimise interest rate cash flow risk exposures on long-term financing. Longer-term borrowings are therefore usually at fixed rates. At 31 December 2017, the Group is exposed to changes in market interest rates through bank borrowings at variable interest rates. Other borrowings are at fixed interest rates. The exposure to interest rates for the Group's money market funds is considered immaterial.

The following table illustrates the sensitivity of profit to a reasonably possible change in interest rates of +/-1%. These changes are considered to be reasonably possible based on observation of current market conditions. The calculations are based on a change in the average market interest rate for each period, and the financial instruments held at each reporting date that are sensitive to changes in interest rates. All other variables are held constant.

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Variable rate instruments		
Financial liabilities	**89,986**	60,253
	89,986	**60,253**

Interest rate sensitivity

	Profit and equity for the period	
31 December 2017	**1%**	**1%**
31 December 2016	1,165	(962)
	305	**(305)**

35.2 Credit risk

Credit risk is the risk of a failure by counterparties to discharge their obligations, which could reduce the amount of future cash inflows from financial assets on hand at the reporting date. The Group has policies in place to ensure that all of its transactions giving rise to credit risk are made with parties having an appropriate credit history, and monitors on a continuous basis the ageing profile of its receivables.

Notes to the consolidated financial statements
continued

35.2 Credit risk *continued*

Also, the Group has policies to limit the amount of credit exposure to any banking institution, considering among other factors the credit ratings of the banks with which deposits are held. Credit quality information in relation to those banks is provided below.

The carrying amount of financial assets represents the maximum credit exposure. The maximum exposure to credit risk at the reporting date, without taking account of any collateral obtained, was:

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Trade receivables	**9,313**	2,143
Other receivables	**184**	3
Cash and cash equivalents and bank deposits	**15,692**	17,586
Total	**25,189**	**19,732**

Credit quality of non-impaired bank deposits

The credit quality of the banks in which the Group keeps its non-impaired deposits is assessed by reference to the credit rating of these banks. The credit ratings of the corresponding banks in which of the Group keeps its deposits as follows:

AA/Aa2
AA/Aa3
Lower than B-/B3

The Company has assessed the recoverability of all cash balances and believe they are presented at fair value within the consolidated statement of financial position.

35.3 Foreign exchange risk

The Group is exposed to foreign exchange risk as it undertakes operations in various foreign currencies. The key sources of the risk are attributed to the fact that the Group has certain subsidiaries with euro functional currencies in which a number of loan agreements denominated in US$ and sales of crude oil are additionally denominated in US$.

The Group's exposure to foreign currency risk at each reporting date is shown in the table below. The amounts shown are the US$ equivalent of the foreign currency amounts.

	Liabilities As at 31 December		Assets As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)	**2017 (US$ 000)**	2016 (US$ 000)
US$ (amounts in US$'000)	**89,985**	272,441	**17,240**	6,423
United Kingdom pounds (amounts in US$'000)	**–**	1,741	**403**	3
Total	**89,985**	**274,182**	**17,643**	**6,426**

The following table reflects the sensitivity analysis for profit and loss results for the year and equity, taking into consideration for the periods presented foreign exchange variation by +/-10%.

	31 December 2017				31 December 2016			
	USD		GBP		USD		GBP	
	Variation 10%	-10%	10%	Variation -10%	10%	Variation -10%	10%	Variation -10%
Profit or loss (before tax)	9,182	(11,222)	77	(112)	25,395	(31,038)	166	203
Other comprehensive income	(1,595)	828	–	–	1,551	(2,707)	–	–
Equity	**7,587**	**(10,394)**	**77**	**(112)**	**26,946**	**(33,745)**	**166**	**203**

The above calculations assume that interest rates remain the same as at the reporting date.

35.4 Liquidity risk

Liquidity risk is the risk that arises when the maturity of assets and liabilities does not match. An unmatched position potentially can increase the risk of losses. The Group has procedures with the object of minimising such losses such as maintaining sufficient cash and other highly liquid current assets and by having available an adequate amount of committed credit facilities.

The following tables detail the Group's remaining contractual maturity for its financial liabilities. The tables have been drawn up based on the undiscounted cash flows of financial liabilities based on the earliest date on which the Group can be required to pay. The table includes both interest and principal cash flows.

The Group manages its liquidity risk by ongoing monitoring of its cash flows. Management budgets and follows up its cash flows and appropriately acts for available cash deposits and credit lines with the banks.

As part of the derivative asset recognition under the Reorganisation and Supplementary Agreement (Note 31.4), there is a contractual cash flow of US$10 million to be paid on either a Sale transaction or an IPO. The carrying value of the derivative asset as of 31 December 2017 is US$93,292.

31 December 2017	Carrying amounts (US$ 000)	Contractual cash flows (US$ 000)	3 months or less (US$ 000)	3-12 months (US$ 000)	1-2 years (US$ 000)	2-5 years (US$ 000)	More than 5 years (US$ 000)
Bank loans	89,986	90,915		12,500	34,500	43,915	
Other loans	1,345	1,345	–	–	1,345	–	–
Trade and other payables	69,073	69,073	52,689	14,393	526	1,465	–
	160,404	**161,333**	**52,689**	**26,893**	**36,371**	**45,380**	**–**

31 December 2016	Carrying amounts (US$ 000)	Contractual cash flows (US$ 000)	3 months or less (US$ 000)	3-12 months (US$ 000)	1-2 years (US$ 000)	2-5 years (US$ 000)	More than 5 years (US$ 000)
Investor loans (Note 9.1)	34,167	35,000	–	35,000	–	–	–
Bank loans	60,253	73,169	858	3,024	3,860	65,427	–
Other loans	1,182	1,182	–	–	1,182	–	–
Trade and other payables	26,547	26,547	26,547	–	–	–	–
Loans from shareholders	214,813	324,573	–	21,130	42,263	261,180	–
	336,962	**460,471**	**27,405**	**59,154**	**47,305**	**326,607**	**–**

36. Other risk management

36.1 Inventory market price risk

External market conditions can impact our financial performance. Supply, demand and the prices achieved for our products can be affected by a wide range of factors including political developments, technological change, global economic conditions and the influence of OPEC.

Hedging activity

The Group does not have a formal hedging policy with regard to the oil price and is limited in the scope of its hedging activities under the terms of its facility agreements with the EBRD. Historically, hedging has been undertaken via zero-cost collars for general downside risk and fixed price contracts to set a fixed price for a set number of barrels for a known future BP lifting to protect against either (i) a fall in the oil price and/or (ii) the pricing optionality afforded to BP under the BP Offtake Agreement.

36.2 Customer concentration risk

The Group's revenue is derived from a single major customer. The loss of this customer would adversely affect the Group's financial position and operating results. The Group takes all reasonable steps to maintain a good relationship with that customer.

Notes to the consolidated financial statements
continued

37. Capital management

The Group for management purposes determines as capital, defined as total equity, including all reserves, plus its shareholders, subordinated debt.

Shareholders' subordinated debt represents loans from the shareholders of the Group. The Group defines net debt as the Group's total borrowings (including current and non-current borrowings) less cash and cash equivalents.

The Group manages its capital and net debt to ensure that it will be able to continue as a going concern while maximising the return to shareholders through the optimisation of the balance between its net debt and capital.

The Group manages its capital structure and takes reasonable steps in the light of changes in economic conditions and the risk characteristics of its underlying business and assets. In order to maintain or improve its capital structure the Group may issue new shares, sell assets to reduce debt, refinance existing borrowings, and/or adjust the amount of any distribution of dividends.

The net debt at the end of the period is calculated using the following amounts, as shown in the consolidated statement of financial position:

	As at 31 December	
	2017 (US$ 000)	2016 (US$ 000)
Bank and other loans	**91,331**	61,435
Cash and cash equivalents and bank deposits	**(15,692)**	(12,977)
Net debt	**75,639**	**48,458**
Total equity	**288,982**	(16,120)
Shareholders' subordinated debt	**–**	214,813
Capital	**288,982**	198,693
Gearing ratio (net debt/capital)	**26.17%**	**24.39%**

38. Subsequent events

On 21 March 2018 the Company completed the admission of its shares to the Premium Segment of the London Stock Exchange and raised gross proceeds of US$460 million.

On 16 March the Company acquired 50% of the preference shares of Energean Israel from its founder shareholders after paying the total consideration of US$10 million (please refer to Note 31.4).

In March 2018, further to a subscription agreement pursuant to which the Group agreed to subscribe for additional shares in Energean Israel Limited for an aggregate consideration of US$266.7 million, the Group acquired an additional 20% of Energean Israel shares, with Kerogen holding the remaining 30%.

In March 2018 the Group proceeded with a Final Investment Decision (FID) on the Karish and Tanin offshore Israel leases. In consequence the Group proceeded with the recognition of a liability in respect of the deferred consideration for the acquisition of the Tanin and Karish leases of US$108.5 million due in ten equal annual payments.

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities — a facility of up to US$105 million with EBRD and the Black Sea Trade and Development Bank (BSTDB) as lenders (the 'IFI Facility') and a US$75 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA ('Romanian ECA') and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders (the 'Romanian Club Facility'). Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP Engineering, Procurement, Construction and Installation Contract (EPCIC).

On 12 February 2018, the Group signed an amendment to the BP Offtake Agreement to extend the contract to supply the produced Prinos crude oil to BP Oil International until the later of a) the expiry of the agreement on 1 November 2025 or b) the delivery of twenty-five million barrels. As of 31 December 2017 the Group has delivered 3,974,667 barrels under the BP Offtake Agreement.

Company statement of profit or loss and other comprehensive income

	Notes	For the period from 8 May 2017 to 31 December 2017 (US$ 000)
General and administrative costs		**(779)**
Operating profit		**(779)**
Gains (losses) on derivative financial Instruments, net	4	**25,786**
Profit/(loss) before taxation		**25,007**
Income tax		**–**
Other comprehensive income		**–**
Total profit/(loss) and other comprehensive income		**25,007**

All capital and reserves are attributable to the owners of the Company, as there is no non-controlling interest.

Company statement of financial position

As at 31 December 2017

	Notes	2017 (US$ 000)
Assets		
Non-current assets		
Investment in subsidiaries		852
		852
Current assets		
Trade and other receivables	3	4,848
Derivative asset	4	93,292
		98,140
Total assets		98,992
Liabilities		
Current liabilities		
Trade and other payables	5	5,562
		5,562
Total liabilities		5,562
Capital and reserves		
Capital and reserves		
Share capital	6	917
Other reserves		67,506
Retained earnings		25,007
Total equity		93,430

Approved by the Board and authorised for issue on 30 April 2018.

Mathios Rigas
Chief Executive Officer

Panos Benos
Chief Financial Officer

Company statement of changes in equity

As at 31 December 2017

	Share capital US$ 000	Other reserves US$ 000	Retained earnings US$ 000	Total equity US$ 000
At 8 May 2017	–	–	–	–
Profit/(loss) for the year	–	–	25,007	25,007
Capital contributions	917	–	–	917
Transactions with owners of the company				
Modification of derivative (Note 4)	–	67,506	–	67,506
At 31 December 2017	**917**	**67,506**	**25,007**	**93,430**

Company accounting policies

As at 31 December 2017

(a) General information

Energean Oil & Gas plc ('the Company') was incorporated in the England & Wales on 8 May 2017 as a public company with limited liability, under the Companies Act 2006. Its registered number is 10758801 and its registered office is at 21 Gloucester Place, London W1U 8HR, United Kingdom. The financial statements are presented in US dollars and all values are rounded to the nearest US$ thousand ('000), except where otherwise stated. Energean Oil & Gas plc is the ultimate parent of the Energean Oil & Gas Group.

(b) Basis of preparation

The Company meets the definition of a qualifying entity under Financial Reporting Standard 100 ('FRS 100') issued by the Financial Reporting Council. The financial statements have therefore been prepared in accordance with Financial Reporting Standard 101 ('FRS 101') 'Reduced Disclosure Framework' as issued by the Financial Reporting Council. As permitted by FRS 101, the Company has taken advantage of the following disclosure exemptions under FRS 101:

a) the requirements of IFRS 7 Financial Instruments: Disclosures;
b) the requirements of paragraphs 91-99 of IFRS 13 Fair Value Measurement;
c) the requirement in paragraph 38 of IAS 1 'Presentation of Financial Statements' to present comparative information in respect of: (i) paragraph 79(a) (iv) of IAS 1 and (ii) paragraph 73(e) of IAS 16 Property Plant and Equipment;
d) the requirements of paragraphs 10(d), 16, 38A to 38D, 40A, 40B, 40C and 40D, 111 and 134 to 136 of IAS 1 Presentation of Financial Statements;
g) the requirements of IAS 7 Statement of Cash Flows;
i) the requirements of paragraph 17 of IAS 24 Related Party Disclosures;
j) the requirements in IAS 24 Related Party Disclosures to disclose related party transactions entered into between two or more members of a group, provided that any subsidiary which is a party to the transaction is wholly owned by such a member;

Where relevant, equivalent disclosures have been given in the Group accounts.

During the year the Company made a profit of US$25.0 million.

(c) Going concern

The Directors have exercised significant judgement in assessing that the preparation of the financial statements on a going concern basis is appropriate. In making this assessment, the factors considered, among others, include the current financial position and the profitability of the Company as well their expectations in relation to future business prospects, and future profitability and cash flows of the Company. Another important factor for determining that the going concern basis remains appropriate is the ability to raise funding as and when needed. Subsequent to the balance sheet date, the Company successfully completed an IPO on the London Stock Exchange and raised $460 million gross proceeds. Accordingly, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future, and consider it appropriate to adopt the going concern basis in preparing the financial statements.

(d) Foreign currencies

The US dollar is the reporting currency of the Company. Transactions in foreign currencies are translated at the rates of exchange ruling at the transaction date. Monetary assets and liabilities denominated in foreign currencies are translated into US dollars at the rates of exchange ruling at the balance sheet date, with a corresponding charge or credit to the income statement.

(e) Investments

Fixed asset investments, including investments in subsidiaries, are stated at cost and reviewed for impairment if there are indications that the carrying value may not be recoverable.

Company accounting policies
continued

(f) Financial instruments at fair value through profit or loss (FVTPL)

FVTPL includes financial instruments held for trading (HFT) and financial instruments designated upon initial recognition at fair value through profit or loss. Financial instruments are classified as HFT if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as HFT. Financial instruments at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value presented as a gain or loss in the statement of profit or loss. The Company's financial instruments that have been classified as HFT are derivative instruments.

(g) Trade and other receivables

Trade receivables, which generally have 30 to 90 day terms, are recognised and carried at the lower of their original invoiced value and recoverable amount. Where the time value of money is material, receivables are carried at amortised cost. Allowance is made when there is objective evidence that the Company will not be able to recover balances in full. Evidence on non-recoverability may include indications that the debtor or group of debtors is experiencing significant financial difficulty, the probability that they will enter bankruptcy or default or delinquency in repayments. Balances are written off when the probability of recovery is assessed as being remote. The amount of the impairment loss is the receivable carrying amount compared to the present value of estimated future cash flows, discounted at the original effective interest rate.

(h) Trade and other payables

Trade and other payables are carried at amortised cost. They represent liabilities for goods and services provided to the Company prior to the end of the financial year that are unpaid and arise when the Company becomes obligated to make future payments in respect of the purchase of those goods and services. The amounts are unsecured and are usually paid within 30 days of recognition.

(i) Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either in the principal market for the asset or liability or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Company uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

All assets and liabilities, for which fair value is measured or disclosed in the financial statements, are categorised within the fair value hierarchy, described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable.

For assets and liabilities that are recognised in the financial statements on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by reassessing categorisation (based on the lowest-level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

(j) Share issue expenses

Costs of share issues are written off against the premium arising on the issues of share capital.

(k) Capital management

The Company defines capital as the total equity of the Company. Capital is managed in order to provide returns for shareholders and benefits to stakeholders and to safeguard the Company's ability to continue as a going concern. The Company is not subject to any externally imposed capital requirements. To maintain or adjust its capital structure, the Company may adjust the dividend payment to shareholders, return capital, issue new shares for cash, repay debt, and/or put in place new debt facilities.

(l) Critical accounting judgements and key sources of estimation uncertainty

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities are discussed below:

Fair value measurements and valuation processes

Some of the Company's assets and liabilities are measured at fair value for financial reporting purposes. In estimating the fair value of an asset or a liability the Company uses market-observable data to the extent that it is possible. Where level 1 inputs are not available, as is the case for the option to purchase Energean Israel Class B shares the Company has used a combination of level 2 and level 3 inputs to estimate the fair value.

The Chief Financial Officer reports the valuations to the Board of Directors of the Company every six months to explain the cause of fluctuations in the fair value of the assets and liabilities.

Information about the valuation technique and inputs used in determining the fair value of the option to purchase Energean Israel Class B shares is disclosed in Note 4.

Notes to the Company financial statements

Note 1. Subsidiary companies

The following table shows the movement in the investment in subsidiaries during the year

	Investment in subsidiaries US$ 000
At 8 May 2017	
Additions	852
At 31 December 2017	852

[1] Energean E&P Holdings Limited was the holding company of the Group until 30 June 2017, when it became a wholly-owned subsidiary of the Company.

A complete list of Energean Oil & Gas Plc Group companies at 31 December 2017, and Group's percentage of share capital are set out in Note 8 of the Group financial statements. All of these subsidiaries have been consolidated in the Group's financial statements.

Note 2. Dividends

No dividends were paid during the period.

Note 3. Trade and other receivables

	31 December 2017 US$ 000
Financial items	
Receivables from shareholders	65
	65
Non-financial items	
Deposits and prepayments	4,783
	4,783
Total trade and other receivables	4,848

The receivable amount from shareholders consists of the nominal value of the initial share capital for the incorporation of the Company. At incorporation, the affiliate company Energean E&P Holdings provided a letter according to which the amount of £50,000 is held available in its bank accounts on behalf of the Company until its shareholders are able to pay the amount. At reporting date, the amount was still outstanding.

The amount included under deposits and prepayments account consists of the costs accrued in 2017 related to the Initial Public Offering (IPO) of the Company, which at reporting date was still in progress. All such costs will be reported in the year the IPO is successfully completed and will be debited against the share capital raised. Such IPO costs are related to the services provided to the Company by the reporting accountants, lawyers and other professionals.

Note 4. Financial instruments

Disclosure exemptions adopted

Where equivalent disclosures for the requirements of IFRS 7 Financial Instruments: Disclosures and IFRS 13 Fair Value Measurements have been included in the 2017 Annual Report and Accounts of Energean Oil & Gas plc, the Company has adopted the disclosure exemptions available to the Company's accounts.

Financial risk management objectives

The Company follows the Group's policies for managing all its financial risks.

Fair values of derivative instruments

The Company has one material financial asset measured at fair value at 31 December 2017 which relates to the Energean Israel B shares. As part of the reorganisation the Company committed on 30 June 2017 to acquire the 50% of the class B shares of Energean Israel Limited in an Exit Event.

The valuation technique used multiplies the estimated likelihood of an Exit (being an IPO or a Sale) by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares to be acquired under the commitment. The key input assumptions used in the fair value measurement calculation are the estimated likelihood of an IPO event and the value of the B shares. An Exit in the form of a Sale is considered to be of negligible likelihood. The other significant inputs are the transaction prices applicable in an Exit Event, which are contractually agreed amounts, and the discount rate assumption used in the calculation, which was 11.5%. The fair value of the derivative asset is a Level 3 fair value measurement in the fair value measurement hierarchy, because the valuation relies significantly on input assumptions that are unobservable.

On remeasurement on 31 December 2017, the value of the B shares was estimated based on the price negotiated at a similar time with a third party for another tranche of the B shares in a separate transaction. The likelihood of a future IPO occurring was estimated as of 31 December 2017 to be 50%, having regard to the considerable progress made to prepare for an IPO as of that date, but also to the fact that there were a number of significant steps not wholly under the control of the Company that remained to be achieved, and the inherent uncertainty in achieving any IPO due to capital market conditions.

The change in fair value of US$25,786 between 30 June 2017 and 31 December 2017 is included in 'Gain on derivative' in the statement of profit or loss as it is due to changes in measurement assumptions.

Also on 31 October 2017, under the Supplementary Agreement the consideration payable to acquire the B shares in the event of an IPO was reduced from $150 million to $10 million. The resulting increase in the value of the derivative asset of US$67,506 (after applying the 50% IPO likelihood assumption and other discounting effects) is recorded in the statement of changes in equity, as the Supplementary Agreement is a transaction with owners, giving the derivative asset a closing value as of 31 October 2017 of $91,615. As of 31 December 2017 the derivative asset was further increased to US$93,292 due to unwinding of the discount applied at the recognition, resulted in additional gain of US$1,677 recorded in profit or loss.

If the probability of an IPO increased to 100%, whilst the probability of a sale was 0% and the discount rate was held constant, the fair value of the derivative asset to purchase Energean Israel Class B shares at 31 December 2017 would increase by US$93,292.

If the discount rate increased from 11.5% to 20%, whilst the probability of an IPO and probability of a sale were held constant, the fair value of the derivative asset to purchase Energean Israel Class B shares at 31 December 2017 would decrease by US$1,135.

Upon recognition, the derivative was the only instrument in the Level 3 category of the fair value hierarchy. There were no transfers in or out of this category in the period, and the only movement in the category relates to the increase in fair value of the derivative.

Notes to the Company financial statements
continued

Note 5. Trade and other payables

	31 December 2017 US$ 000
Financial items	
Accrued expenses	3,674
Staff costs accrued	1,849
Other creditors	36
Trade payables	3
Total trade and other receivables	5,562

The amount reported under accrued expenses related to the IPO costs accrued during the year plus accruals for accounting and statutory audit fees.

The amount reported under staff costs accrued derived from the relevant letters of appointment of the non-executive Directors of the Company as well as the employment agreement with the executive Directors.

Note 6. Share capital

The Company's initial share capital amounted to £50 (US$65), consisting of an issuance of 50,000 ordinary shares of a nominal value of £1.00 (US$1.3) each on 8 May 2017. On 30 June 2017 the Company effected a 100 for 1 share split resulting in 5,000,000 ordinary shares of a nominal value of £0.01 (US$0.013) each.

On 30 June 2017, the Company also became the parent company of the Group through the acquisition of the full share capital of Energean E&P Holdings Limited, in exchange for 65,643,120 £0.01 (US$0.013) shares in the Company issued to the previous shareholders. As of this date, the Company's share capital increased from £50 (US$65) to £706 (US$917).

	Number of shares	31 December 2017 US$ 000
(a) Authorised		
Ordinary shares of £1 each	70,643,120	917
(b) Fully paid ordinary shares	65,643,120	852

Note 7. Directors' remuneration

Directors' remuneration has been provided in the group financial statements. Please refer to note 31 of the Group financial statements

Note 8. Auditors' remuneration

Auditors' remuneration has been provided in the group financial statements. Please refer to note 23 of the group financial statements for details of the remuneration of the company's auditor on a group basis.

Note 9. Events after reporting period

Please refer to note 38 of the Group financial statements

Payments to governments (unaudited)

Energean pays to several countries numerous taxes, including withholding taxes, PAYE and National Insurance on personnel employed, licence fees, royalties and other taxes.

The main economic value to host governments is from payroll and other withholding taxes on Energean's activities.

$7.4M
paid to governments

Transparency disclosure

The Reports on Payments to Governments Regulations (UK Regulations) came into force on 1 December 2014 and require UK companies in the extractive sector to publicly disclose payments made to governments in the countries where they undertake extractive operations. The regulations implement Chapter 10 of EU Accounting Directive (2013/34/EU). The UK Regulations came into effect on 1 January 2015. The 2016 disclosure remains in line with the EU Directive and UK Regulations and we have provided additional voluntary disclosure on withholding taxes, PAYE and other taxes.

The payments disclosed are based on where the obligation for the payment arose: payments raised at a project level have been disclosed at project level and payments raised at a corporate level have been disclosed on that basis. However, where a payment or a series of related payments do not exceed £86,000, they are disclosed at a corporate level, in accordance with the UK Regulations.

The voluntary disclosure has been prepared on a corporate level. All of the payments disclosed in accordance with the Directive have been made to National Governments, either directly or through a Ministry or Department of the National Government, with the exception of Greek payments in respect of production royalties and licence fees, which are paid to the Hellenic Hydrocarbon Resources Management SA.

Royalties – represent cash royalties paid to the Greek Government during the year for the extraction of oil. The terms of the royalty paid described within our Lease Agreement for Prinos area. The cash payment of royalties occurs within a three months' period from the end of the year in which the royalty payment obligation has arisen.

Licence fees – represent licence fees, rental fees, entry fees and other consideration for licences and/or concessions paid for access to an area during the year (with the exception of signature bonuses which are captured within bonus payments).

Withholding tax (WHT) – represent tax charged mainly on services and royalties. The amount disclosed is equal to the WHT return submitted by Energean to governments with the cash payment made in the year the charge is borne.

PAYE and national insurance – represent payroll and employer taxes paid (such as PAYE and national insurance) by Energean as a direct employer. The amount disclosed is equal to the return submitted by Energean to governments with the cash payment made in the year the charge is borne.

Training allowances – comprise payments made in respect of training government or national oil company staff. This can be in the form of mandatory contractual requirements or discretionary training provided by a company.

VAT – Represents net cash VAT received from/paid to governments during the year. The amount disclosed is equal to the VAT refunds/payments made by Energean to governments on a cash basis.

Other taxes – comprise payments made in respect taxes other than the above including annual levies, stamp duties etc.

Transparency disclosure (unaudited)

	European transparency directive disclosure									Voluntary disclosure							
Licence / Company level	Production entitlements	Production entitlements	Income taxes	Royalties (cash only)	Dividends	Bonuses payments	Licence fees	Infrastructure improvement payments		VAT	Stamp duty	Withholding tax	PAYE and national insurance	Training allowances duties	Other	Total	Total
	BBL000	$000	$000	$000	$000	$000	$000	$000		$000	$000	$000	$000	$000	$000	$000	BBL000
Energean Oil & Gas SA																	
Greece – Prinos licence	–	–		418.10						(5,973.54)	32.42	690.47	2,896.22		9.56	(1,926.77)	–
Greece – South Kavala licence	–	–														–	–
Greece – Ioannina licence	–	–					58.66									58.66	–
Greece – Katakolo licence	–	–					38.00									38.00	–
Kavala Oil SA	–	–								44.97	1.95	51.51	7,566.43		6.26	7,671.11	–
Greek Government Report	**–**	**–**	**–**	**418.10**	**–**	**–**	**96.66**	**–**		**(5,928.57)**	**34.37**	**741.98**	**10,462.65**	**–**	**15.82**	**5,841.00**	**–**
Energean Israel Limited																	–
Israel – Karish licence	–	–					146.47										–
Israel – Tanin licence	–	–					149.46										–
Israel – Blocks 12, 21, 22, 23 & 31	–	–					105.98										
Israeli Government Report	**–**	**–**	**–**	**–**	**–**	**–**	**401.90**	**–**		**(246.33)**	**–**	**7.33**	**125.71**	**–**	**–**	**288.61**	**–**
Energean International Limited																	
Egypt – West Kom Ombo Block	–	–	–	–	–							6.49	96.37		15.19	118.06	–
Egypt Government Report	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**		**–**	**–**	**6.49**	**96.37**	**–**	**15.19**	**118.06**	**–**
Energean Montenegro Limited																	–
Montenegro – Block 4218-30	–	–	–	–	–	–	168.62	–									–
Montenegro – Block 4219-26	–	–	–	–	–	–	38.63	–									–
Montenegrin Government Report	**–**	**–**	**–**	**–**	**–**	**–**	**207.25**	**–**		**–**	**–**	**–**	**8.86**	**–**	**–**	**216.11**	**–**
Energean E&P Holdings Limited	–	–		–	–	–	–	–					181.30	–	0.40	181.70	–
Energean International Limited	–	–		–	–	–	–	–					41.33	–	2.37	43.70	–
Energean Israel Limited	–	–		–	–	–	–	–					–	–	0.39	0.39	–
Energean Montenegro Limited	–	–		–	–	–	–	–						–	0.79	0.79	–
Cyprus Government Report	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**		**–**	**–**	**–**	**222.63**	**–**	**3.95**	**226.59**	**–**
Energean Oil & Gas plc	–	–		–	–	–	–	–		–	–	–	–	–	–	–	–
Energean International Limited (UK Branch)	–	–		–	–	–	–	–		(163.23)	–	–	898.55			735.32	–
UK Government Report	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**		**(163.23)**	**–**	**–**	**898.55**	**–**	**–**	**735.32**	**–**
	–	**–**	**–**	**418.10**	**–**	**–**	**705.81**	**–**		**(6,338.13)**	**34.37**	**755.80**	**11,814.78**	**–**	**34.96**	**7,425.68**	**–**

Glossary

CO_2	Carbon dioxide
H_2S	Hydrogen sulphide
SO_2	Sulphur dioxide
GBP or £	Pound Sterling
USD or $	US Dollar
EUR or €	Euro
NOK	Norwegian Krone

A

ACQ	Annual Contract Quantity
AGM	Annual General Meeting
ALARP	As low as reasonably practicable (This a term often used in the regulation and management of safety-critical and safety-involved systems.)

B

Bbl	Barrel
Bcf	Billion cubic feet
BCM	Billion cubic metres
Boe	Barrel of oil equivalent
Boepd	Barrels of oil equivalent per day
Bopd	Barrels of oil per day

C

CAGR	Compound annual growth rate
Capex	Capital Expenditure
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CMAPP	Corporate Major Accident Prevention Policy
CNG	Compressed natural gas
CPR	Competent Person's Report
CSR	Corporate Social Responsibility

D

DCQ	Daily Contract Quantity

E

E&P	Exploration and production
EBITDAX	Earnings before interest, tax, depreciation, amortisation and exploration expenses
EBRD	European Bank for Reconstruction and Development
EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EPCIC	Engineering, Procurement, Construction, Installation and Commissioning

F

FAR	Fatal Accident Rate – number of fatalities per 100 million hours worked
FDP	Field Development Plan
FEED	Front-end Engineering and Design
FID	Final Investment Decision
FPSO	Floating Production Storage and Offloading vessel
FRC	Financial Reporting Council
FRS	Financial Reporting Standard

G

G&A	General and Administrative
GSPA	Gas Sale and Purchase Agreement
GSP	GSP Offshore S.R.L.

H

H&S	Health and Safety
HMRC	HM Revenue and Customs
HSE	Health, Safety and Environment

I

IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
INGL	Israel Natural Gas Lines Ltd
IPO	Initial Public Offering
IPP	Independent Power Producers
IR	Investor Relations

J

JOA	Joint Operating Agreement
JV	Joint Venture

K

kboepd	Thousands of barrels of oil equivalent per day
km	Kilometres
KPI	Key Performance Indicator

L

LIBOR	London Interbank Offered Rate
LSE	London Stock Exchange
LTI	Lost Time Injury
LTIF	Lost Time Injury Frequency

M

M_3	Cubic metre
MARPOL	(Marine pollution) International Convention for the Prevention of Pollution from Ships
MM	Million
MMbbls	Million barrels
MMbo	Million barrels of oil
MMboe	Million barrels of oil equivalents
MMbtu	Million British Thermal Units
MMscf	Million standard cubic feet
MMscf/day or MMscfd	Million standard cubic feet per day
MMtoe	Million tonnes of oil equivalent
MoU	Memorandum of Understanding

N

NGF	Natural Gas Framework
NGO	Non-Governmental Organisation
NPV	Net Present Value
NSAI	Netherland, Sewell & Associates, Inc.

O

OECD	Organisation for Economic Co-operation and Development
Opex	Operating expenses
OR	Or Power Energies

P

PP&E	Property, plant and equipment
Psi	Pounds per square inch

R

2P reserves	Proven and probable reserves
RBL	Reserve Based Lending
2C resources	Contingent resources

S

Sq km or km^2	Square kilometres
STOB	Stock Tank Oil Barrels

T

Tcf	Trillion cubic feet
TRIR	Total Recordable Injury Rate

W

WI	Working interest

Notes

Notes

Company information

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Energean Oil & Gas plc
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W1U 8HR
Tel: +44 203 8593 540

Corporate Brokers
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E14 4QA

Auditor
Ernst & Young LLP
1 More London Place
London
SE1 2AF

Legal Adviser
White & Case LLP
5 Old Broad Street
London
EC2N 1DW

Financial PR Adviser
Instinctif Partners
65 Gresham Street
London
EC2V 7NQ

Registrar
Computershare Investor Services plc
The Pavilions
Bridgwater Road
Bristol
BS13 8AE

Financial calendar
28 June 2018: Annual General Meeting

Forward-looking statements
This annual report may include statements that are, or may be deemed to be, "forward-looking statements". These forward-looking statements may be identified by the use of forward-looking terminology, including the terms "believes", "estimates", "plans", "projects", "anticipates", "expects", "intends", "may", "will" or "should" or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy, plans, objectives, goals, future events or intentions. These forward-looking statements include all matters that are not historical facts and involve predictions. Forward-looking statements may and often do differ materially from actual results.

In addition, even if results or developments are consistent with the forward-looking statements contained in this announcement, those results or developments may not be indicative of results or developments in subsequent periods. Any forward-looking statements reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's business, results of operations, financial position, liquidity, prospects, growth or strategies and the industry in which it operates. Forward-looking statements speak only as of the date they are made and cannot be relied upon as a guide to future performance.

This Annual Report is available at www.energean.com
Designed and produced by Instinctif Partners www.creative.instinctif.com

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נספח 3

דיווחים מאז הדו"ח השנתי 2017

RNS Number : 6407M
Energean Oil & Gas PLC
30 April 2018

For immediate release 30 April 2018

Energean Oil & Gas plc
("Energean" or the "Group")
Publication of Annual Report 2017

London, 30 April 2018 - Energean Oil & Gas has today published its IFRS Annual Report and accounts for the year ended 31 December 2017.

The full report is available for download on the Company's website at www.energean.com.

A copy of the report has also been submitted to the FCA's National Storage Mechanism and will shortly be available for inspection at http://www.morningstar.co.uk/uk/NSM.

Enquiries

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Sotiris Chiotakis (Media Relations) **+30 210 8174 242**

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David Simonson
Laura Syrett
George Yeomans

About Energean Oil & Gas

Energean is a London premium-listed independent E&P company focused on the Eastern Mediterranean region, where it operates offshore Israel, Greece and the Adriatic. It is the only oil and gas producer in Greece and it and its predecessors have a combined 36-year history of operating offshore and onshore assets in environmentally sensitive areas. Energean employs 388 oil and gas professionals. The Group has 2P reserves of 51 MMbbls of oil and 6 Bcf of gas and 2C resources of 22.9 MMbbls of oil and 11.5 Bcf of gas at its Prinos Basin and Katakolo fields. Its subsidiary, Energean Israel, has 2C resources of 32.8 MMbbls of liquids and 2.4 Tcf of gas.

The Company received approval in August 2017 from the Israeli Government of the FDP for the Karish and Tanin fields, offshore Israel, aiming to use an FPSO and produce first gas in 2021. In March 2018, the Group proceeded with a Final Investment Decision on the Karish and Tanin leases. The Company is also pursuing an ongoing investment and development programme to increase production from the Prinos and Prinos North oil fields and develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece. The Company has secured a 25-year exploitation license for the Katakolo offshore block in Western Greece.

The Company also has significant exploration potential in the other licences held in offshore Israel, Western Greece, and Montenegro.

www.energean.com

This information is provided by RNS
The company news service from the London Stock Exchange

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ACSURRNRWSASOAR

RNS Number : 9574M
Energean Oil & Gas PLC
03 May 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Israeli Supreme Court dismisses petition against the Karish-Tanin Development

London, 3 May 2018 - Energean Oil & Gas (ENOG: LSE), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, announces that the petition filed by Hof Hacarmel Regional Council against the Israeli Ministry of Energy, the Petroleum Commissioner, two Planning and Construction authorities, Energean Israel and an environmental union of local authorities for Sharon-Carmel, in connection with the Karish-Tanin Development, has been dismissed by the Israeli Supreme Court.

Energean's Field Development Plan for the Karish-Tanin Development was approved by the Israeli Petroleum Commissioner in August 2017. The Company approved the Final Investment Decision to proceed with the Karish-Tanin Development in March 2018, having secured finance and equity funding for the project, and having signed twelve Gas Sale & Purchase Agreements with significant industrial consumers in the Israeli market for a total of 61 BCM of natural gas over an average period of 16 years.

Energean is planning to deliver gas to the Israeli market from the Karish-Tanin Development in 2021, and is on track with its project milestones to achieve this timeline.

Enquiries

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The Company received approval in August 2017 from the Israeli Government of the FDP for the Karish and Tanin fields, offshore Israel, and produce first gas in 2021. In March 2018, the Group proceeded with a Final Investment Decision on the Karish and Tanin leases. The Company is also pursuing an ongoing investment and development programme to increase production from the Prinos and Prinos North oil fields and develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece. The Company has secured a 25-year exploitation license for the Katakolo offshore block in Western Greece.

The Company also has significant exploration potential in the other licences held in offshore Israel, Western Greece, and Montenegro.

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The company news service from the London Stock Exchange

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RNS Number : 3043N
Energean Oil & Gas PLC
08 May 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Energean receives Class approval for FPSO design for Karish-Tanin

London, 8 May 2018 - Energean Oil & Gas (ENOG: LSE), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, announces that it has received Class approval from DNV-GL, the global quality assurance body, for the Basic Design of the new-build Floating Production Storage and Offloading ("FPSO") that will be deployed at its deep water Karish-Tanin development, offshore Israel.

This rapid obtainment of Class approval reflects the maturity of the FPSO design at Final Investment Decision ("FID") and keeps the development on track to cut first steel as planned before the end of 2018.

Early Class approval was viewed as a critical milestone and its achievement, on schedule, validates the adopted strategy of building upon an existing hull design from TechnipFMC subsidiary, Inocean.

Enquiries

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www.energean.com

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The company news service from the London Stock Exchange

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RNS Number : 3718P
Energean Oil & Gas PLC
25 May 2018

London, 25 May 2018

Energean Oil & Gas plc
("Energean" or the "Company")

Notice of Annual General Meeting

Energean Oil & Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, today announces that the Notice of Annual General Meeting and associated Form of Proxy, together with the Annual Report and Accounts for the year ended 31 December 2017, have been distributed to its shareholders.

The Company's 2018 Annual General Meeting will be held at the offices of White & Case LLP, 5 Old Broad Street, London, EC2N 1DW on Thursday 28 June 2018 at 11:00 a.m. (BST).

Pursuant to Listing Rule 9.6.1, copies of the Notice of Annual General Meeting and Form of Proxy have been submitted to the National Storage Mechanism and will shortly be available for inspection at www.morningstar.co.uk

Electronic copies of the Annual Report and 2017 Accounts continue to be available to download from the Company's website: www.energean.com, together with the Notice of Annual General Meeting.

For further information please visit www.energean.com

Click on, or paste the following link into your web browser, to view the associated PDF document.

http://www.rns-pdf.londonstockexchange.com/rns/3718P_-2018-5-25.pdf

Enquiries

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RNS Number : 9284P
Energean Oil & Gas PLC
31 May 2018

Thursday, 31st May 2018

Energean Oil & Gas plc

("Energean" or the "Company")

Director/PDMR Shareholding

Notification and public disclosure of transactions by persons discharging managerial responsibilities ("PDMRs") and persons closely associated with them

Energean Oil & Gas plc (LSE: ENOG) announces that certain employees have been granted awards over ordinary shares of 1p each in the Company ("Ordinary Shares") under its 2018 Long-Term Incentive Plan (the "LTIP"). These LTIP Awards are granted in respect of the Admission Awards made in connection with the Company's initial public offering, as disclosed in the Company's prospectus.

In relation to each PDMR, details of the number of shares under the awards and of each PDMR are detailed below.

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Steven Moore
2	**Reason for the notification**	
a)	Position/status	Chief Growth Officer
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Award over shares following the Energean Oil & Gas IPO under its Long Term Incentive Plan
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 76412
d)	Aggregated information - Aggregated volume - Price	N/A
		2018-05-24

e)	Date of the transaction	BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Fred Riddiford
2	**Reason for the notification**	
a)	Position/status	Group Reservoir Engineering Manager
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Award over shares following the Energean Oil & Gas IPO under its Long Term Incentive Plan
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 22923
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-05-24 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	

a)	Name	David Donaldson
2	**Reason for the notification**	
a)	Position/status	Managing Director, Kavala Oil S.A.and Prinos Asset Manager
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Award over shares following the Energean Oil & Gas IPO under its Long Term Incentive Plan
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 22923
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-05-24 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Dimitris Gontikas
2	**Reason for the notification**	
a)	Position/status	Managing Director and Vice Chairman, Energean Oil and Gas S.A.
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05

4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Award of shares following the Energean Oil & Gas IPO under its Long Term Incentive Plan
c)	Price(s) and volume(s)	Price(s): Nil Volume(s): 22923
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-05-24 BST
f)	Place of the transaction	Outside a trading venue

Enquiries

Energean Oil & Gas Plc

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David Simonson

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DSHLLFSREDILVIT

RNS Number : 3634Q
Energean Oil & Gas PLC
05 June 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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PMELLFILRFIEIIT

RNS Number : 3224R
Energean Oil & Gas PLC
13 June 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

PMELLFVEREIVLIT

RNS Number : 3234R
Energean Oil & Gas PLC
13 June 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBUGDLGSBBGIX

RNS Number : 3189S
Energean Oil & Gas PLC
25 June 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Energean to drill Karish North exploration well

London, 25 June 2018 - Energean Oil and Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, is pleased to announce that the Board has made the decision to drill an exploration well in the Karish North prospect, offshore Israel, with a planned spud date before end-March 2019, subject to necessary approvals. This will exercise the first of seven optional wells included in the Stena Drilling contract.

The Karish North prospect is located within Energean's Karish lease and will be drilled immediately prior to the three well development of the adjacent Karish Main field, the Company's flagship gas development project. Gross drilling costs are expected to be between US$15-25 million. The Independent Competent Persons Report[1] for the Karish North prospect estimates gross recoverable unrisked prospective resources of 33.5 BCM (1.2 Tcf, or circa 200 MMboe) of natural gas and 14 MMbbls of light oil. The Karish lease is 100% owned and operated by Energean Israel Ltd, which is 70% owned by Energean.

The decision to drill the Karish North well is consistent with Energean's exploration strategy to target near field prospects where potential discoveries can be quickly and economically monetised.

The Karish FPSO is being built with gas production and processing capacity of 8 BCMA. Energean Israel has forward sold 4.2 BCMA of currently discovered gas volumes, leaving circa 4 BCMA of excess FPSO capacity available for the potential tie-back of future discoveries.
The option to drill additional exploration wells at the end of the development well campaign remains open. Options for a second well include the Karish East prospect in the Karish lease and Prospect 4 in the Block 12 exploration licence, which Energean secured at the end of 2017, following the First Israeli Offshore Bid Round.

Mathios Rigas, CEO Energean Oil & Gas, commented:
"We view Karish North as an attractive near-field exploration opportunity offshore Israel that could deliver significant upside alongside our existing Karish development, for which we have already signed 12 gas contracts and secured 4.2 BCMA of supply over an average period of 16 years. The goal of the exploration work is to identify further easy-to-commercialise resources in the region."

[1]The January 2018 Netherland Sewell & Associates, Inc. Independent Competent Persons Report

Enquiries

Energean
Mathios Rigas, CEO
Panos Benos, CFO
Sotiris Chiotakis (Media Relations)
Tel: + 30210 8174242

Camarco (Financial PR)
Billy Clegg
Georgia Edmonds
Owen Roberts
Tel: 020 3757 4980

About Energean Oil & Gas
Energean is a London Premium-Listed independent E&P company focused on the Eastern Mediterranean region, where it operates in offshore Israel, Greece and the Adriatic and holds 13 licences. The Group has 2P reserves of 51 MMbbls of oil and 6 Bcf of gas and 2C resources of 45.9 MMbbls of oil and 1.7 Tcf of gas across its Eastern Mediterranean asset portfolio.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos

and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25-year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

www.energean.com

Glossary

BCM	billions cubic meters
BCMA	billions cubic meters per annum
FPSO	floating productions storage and offloading
MMbbls	millions of barrels of oil
MMboe	millions of barrels of oil equivalent
TCF	trillion cubic feet

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END

DRLFZLFLVQFZBBQ

RNS Number : 9270S
Energean Oil & Gas PLC
28 June 2018

28 June 2018

Energean Oil & Gas plc
("Energean" or the "Company")

Results of AGM

Energean Oil & Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, today announces that at its Annual General Meeting ("AGM") held today at the offices of White & Case LLP, 5 Old Broad Street, London, EC2N 1DW, all resolutions put before the meeting were duly passed.

Details of the voting by way of a poll at the AGM in respect of each resolution are shown in the table below and will shortly be available on the Company's website, www.energean.com.

Res. Number	Resolution	VOTES FOR	%	VOTES AGAINST	%	VOTES TOTAL	% of ISC VOTED	VOTES WITHHELD
01/01	ACCOUNTS AND REPORTS	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/02	REMUNERATION REPORT	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/03	APPOINT S HEALE	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/04	APPOINT M RIGAS	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/05	APPOINT P BENOS	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/06	APPOINT A BARTLETT	106,250,034	100.00	0	0.00	106,250,034	69.52%	10,741
01/07	APPOINT R PECK	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/08	APPOINT O MARANI	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/09	APPOINT K SIMON	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/10	APPOINT D BONANNO	105,382,857	99.17	877,918	0.83	106,260,775	69.53%	0
01/11	APPOINT E TOPOUZOGLOU	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
	REAPPOINT							

01/12	AUDITOR	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/13	AUDITOR REMUNERATION	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/14	ALLOT SECURITIES	106,260,775	100.00	0	0.00	106,260,775	69.53%	0
01/15	PRE-EMPTION RIGHTS	106,221,324	99.96	39,451	0.04	106,260,775	69.53%	0
01/16	MEETING NOTICE TIMES	106,107,066	99.86	153,709	0.14	106,260,775	69.53%	0
01/17	MARKET PURCHASES	106,260,775	100.00	0	0.00	106,260,775	69.53%	0

Issued capital: 152823238

END

Enquiries

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Sotiris Chiotakis (Media Relations)

Camarco (Financial PR)
Billy Clegg **Tel: 020 3757 4980**
Georgia Edmonds
Owen Roberts

About Energean Oil & Gas

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In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25-year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

www.energean.com

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RNS Number : 1603T
Energean Oil & Gas PLC
02 July 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Kavala Oil Tax Appeal Final Decision

London, 2nd July 2018 - Energean Oil and Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, announces that the Athens Administrative Court of Appeal has ruled in favour of Energean in its final decision on the Company's appeal against certain tax and transfer pricing penalties. Although the decision is considered to be final and binding, the tax authorities have the right to submit an appeal before the Council of State.

In its 2017 Annual Report and Accounts, Energean had recorded a provision of US$6.9 million for the tax and transfer pricing penalties relating to fiscal years 2006-2011, which were the subject of this appeal. Following receipt of the final decision this provision can be reversed. During 2015, Energean had been required to make a mandatory prepayment of 50% of the total exposure, €3.2 million, to the Greek tax authorities. Following the final decision, Energean will proceed in recovering this amount.

Enquiries

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Kate Sloan

Camarco (Financial PR) **Tel: 020 3757 4980**
Billy Clegg
Georgia Edmonds
Owen Roberts

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In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

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END

UPDLLFFRDAILIIT

RNS Number : 2656T
Energean Oil & Gas PLC
02 July 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

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END

PMELLFILDFIFIIT

RNS Number : 2680T
Energean Oil & Gas PLC
02 July 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

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END

APMBBGDRRGGBGID

RNS Number : 6435T
Energean Oil & Gas PLC
05 July 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Israeli Supreme Court dismisses petition against the Karish-Tanin Development

London, 5 July 2018 - Energean Oil and Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, announces that on 3 July 2018the Israeli Supreme Court, sitting as the High Court of Justice, unanimously dismissed the petition filed on 14 September 2017 by two environmental groups against Energean and the Petroleum Commissioner, the Ministry of Energy, the Ministry of Environmental Protection and the Ministry of Finance, in connection with the Karish-Tanin Development.

These proceedings constituted the sole outstanding court proceedings against Energean in Israel.

Energean is planning to deliver gas to the Israeli market from the Karish-Tanin Development in 2021, and is on track with its project milestones to achieve this timeline.

Enquiries

Energean **Tel: 020 3859 3540**
Kate Sloan, Head of IR

Camarco (Financial PR) **Tel: 020 3757 4980**
Billy Clegg
Georgia Edmonds
Owen Roberts

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www.energean.com

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END

UPDEAKXLEFKPEFF

RNS Number : 9225T
Energean Oil & Gas PLC
06 July 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

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END

PMELLFVEDEIRIIT

RNS Number : 7834U
Energean Oil & Gas PLC
16 July 2018

Monday, 16th July 2018

Energean Oil & Gas plc

("Energean" or the "Company")

Director/PDMR Shareholding

Notification and public disclosure of transactions by persons discharging managerial responsibilities ("PDMRs") and persons closely associated with them

Energean Oil & Gas plc (LSE: ENOG) announces that certain employees have been granted awards over ordinary shares of 1p each in the Company ("Ordinary Shares") under its 2018 Long-Term Incentive Plan (the "LTIP").

In relation to each PDMR, details of the number of shares under the awards and of each PDMR are detailed below.

<table>
<tr><td>1</td><td colspan="2">Details of the person discharging managerial responsibilities / person closely associated</td></tr>
<tr><td>a)</td><td>Name</td><td>Matthaios Rigas</td></tr>
<tr><td>2</td><td colspan="2">Reason for the notification</td></tr>
<tr><td>a)</td><td>Position/status</td><td>Chief Executive Officer</td></tr>
<tr><td>b)</td><td>Initial notification /Amendment</td><td>Initial notification</td></tr>
<tr><td>3</td><td colspan="2">Details of the issuer</td></tr>
<tr><td>a)</td><td>Name</td><td>Energean Oil & Gas plc</td></tr>
<tr><td>b)</td><td>LEI</td><td>549300RVMKU0CYUZBB05</td></tr>
<tr><td>4</td><td colspan="2">Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted</td></tr>
<tr><td>a)</td><td>Description of the financial instrument, type of instrument

Identification Code</td><td>Ordinary shares of 1p each

GB00BG12Y042</td></tr>
<tr><td>c)</td><td>Nature of the transaction</td><td>Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. The award will be subject to a further two year holding period ending on 30 June 2023.</td></tr>
<tr><td>c)</td><td>Price(s) and volume(s)</td><td><table><tr><td>Price(s)</td><td>Volume(s)</td></tr><tr><td>Nil</td><td>252,904</td></tr></table></td></tr>
</table>

d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Panos Benos
2	**Reason for the notification**	
a)	Position/status	Chief Financial Officer
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. The award will be subject to a further two year holding period ending on 30 June 2023.
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 168,602
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Steven Moore
2	**Reason for the notification**	
a)	Position/status	Chief Growth Officer
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. No further holding period will apply.
c)	Price(s) and volume(s)	Price(s): Nil Volume(s): 6,634
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Shaul Zemach
2	**Reason for the notification**	

a)	Position/status	Country Manager Israel
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. No further holding period will apply.
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 12,727
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Fred Riddiford
2	**Reason for the notification**	
a)	Position/status	Group Reservoir Engineering Manager
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of**	

4	**Details of the transaction(s): section to be repeated for (i) each type of instrument, (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. No further holding period will apply.
c)	Price(s) and volume(s)	Price(s): Nil Volume(s): 11,599
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	David Donaldson
2	**Reason for the notification**	
a)	Position/status	Managing Director, Kavala Oil S.A.and Prinos Asset Manager
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period

		ending on 30 June 2021. No further holding period will apply.
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 6,959
d)	Aggregated information - Aggregated volume - Price	N/A
e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

1	**Details of the person discharging managerial responsibilities / person closely associated**	
a)	Name	Dimitris Gontikas
2	**Reason for the notification**	
a)	Position/status	Managing Director and Vice Chairman, Energean Oil and Gas S.A.
b)	Initial notification /Amendment	Initial notification
3	**Details of the issuer**	
a)	Name	Energean Oil & Gas plc
b)	LEI	549300RVMKU0CYUZBB05
4	**Details of the transaction(s): section to be repeated for (i) each type of instrument; (ii) each type of transaction; (iii) each date; and (iv) each place where transactions have been conducted**	
a)	Description of the financial instrument, type of instrument Identification Code	Ordinary shares of 1p each GB00BG12Y042
c)	Nature of the transaction	Conditional award over shares under the Energean Oil & Gas Plc 2018 Long Term Incentive Plan. The award is subject to a performance period ending on 30 June 2021. No further holding period will apply.
c)	Price(s) and volume(s)	Price(s): Nil; Volume(s): 12,427
d)	Aggregated information - Aggregated volume - Price	N/A

e)	Date of the transaction	2018-07-12 BST
f)	Place of the transaction	Outside a trading venue

Enquiries

Energean **Tel: 020 3859 3540**
Kate Sloan, Head of IR

Camarco (Financial PR) **Tel: 020 3757 4980**

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Energean is a London Premium-Listed independent E&P company focused on the Eastern Mediterranean region, where it operates in offshore Israel, Greece and the Adriatic and holds 13 licences. The Group has 2P reserves of 51 Mmboe plus 2C resources of 45.9 Mmbbls oil and 1.7 Tcf of gas.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25 year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

www.energean.com

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END

DSHLLFEVDIIRLIT

RNS Number : 0312W
Energean Oil & Gas PLC
27 July 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

PMELLFILDFIDFIT

RNS Number : 0331W
Energean Oil & Gas PLC
27 July 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBBGDRRGDBGIR

RNS Number : 3279W
Energean Oil & Gas PLC
31 July 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

PMELLFILDFILVIT

RNS Number : 3288W
Energean Oil & Gas PLC
31 July 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBBGDRRGXBGIB

RNS Number : 9419W
Energean Oil & Gas PLC
06 August 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

PMELLFILTFIRIIT

RNS Number : 9427W
Energean Oil & Gas PLC
06 August 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBBGDIRGGBGIL

RNS Number : 9445X
Energean Oil & Gas PLC
16 August 2018

For immediate release

Energean Oil & Gas plc
("Energean" or the "Company")

Independent certification of reserves and resources in Israel

"7.5 Tcf of Prospective Resources - Increase in net 2P reserves from 51 to 349 mmboe[1]"

London, 16 August 2018 - Energean Oil and Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, is pleased to announce that it has received an updated independent Competent Persons Report from Netherland Sewell & Associates ("NSAI") for its Israeli portfolio. The updated CPR includes the certification of 63 bcm (2.2 Tcf) of 2P reserves and 7.5 Tcf of gross prospective resources and is the first assessment of prospective resources in the new Blocks (12, 21, 22, 23 and 31) that were awarded as part of the recent offshore licencing round.

The updated CPR includes 63 bcm (2.2 Tcf) of gas and 31.8 million barrels of liquids (gross, Energean 70%) of 2P reserves in the Karish and Tanin fields. Energean's independently certified net 2P reserves are now 349 mmboe, an increase from the 51 mmboe estimated when Energean undertook its London Stock Exchange listing in March 2018.

Contingent resources in the Karish field of 5.4 bcm (0.2 Tcf) of gas and 1.0 million barrels of liquids (Gross, Energean 70%) are recognised. Remaining contingent resource relates to the Karish B reservoir. Overall 2P reserves plus contingent resources across the Karish and Tanin leases remain the same.

The updated CPR also recognises gross recoverable prospective resources of 212 bcm (7.5 Tcf) of gas and 101 million barrels of liquids (Energean 70%), consistent with Energean's view that its acreage contains an attractive number of near-field prospects where potential discoveries can be quickly and economically monetised. The Karish FPSO is being built with gas production and processing capacity of 8 bcm/yr. Energean Israel (Energean 70%) has sold 4.2 bcm/yr of discovered gas volumes, leaving 3.8 bcm/yr of available FPSO capacity for the potential tie-back of future discoveries.

Energean recently committed to drill a well in the Karish North exploration prospect. NSAI estimates that the Karish North well will target 38 bcm (1.3 Tcf) of gas and 16.4 million barrels of liquids (gross, Energean 70%) and has a 69% volume weighted probability of geological success. The option to drill additional exploration wells remains open; Energean has six options remaining within its Stena drilling contract.

Mathios Rigas, CEO Energean Oil & Gas, commented:
"We are pleased that our independent reserves auditors have identified 7.5 Tcf of prospective resource across our Israeli acreage with a very high probability of geological success, across which we have limited exploration capital commitments. The outcome is consistent with Energean's view that our portfolio contains multiple attractive near-field exploration opportunities that could deliver significant upside alongside our existing Karish and Tanin development. The conversion of contingent resources demonstrates our commitment to increasing reserves and underpins a more-than-six times increase in our independently verified 2P reserves at IPO."

Enquiries

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Billy Clegg
Georgia Edmonds
Owen Roberts

About Energean Oil & Gas plc
Energean is a London Premium Listed independent E&P company focused on the Eastern Mediterranean region, where it operates in offshore Israel, Greece and the Adriatic and holds 13 licences. Energean has 349 mmboe of 2P reserves and 48 mmboe of 2C resources across its portfolio.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece,

the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25 year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

1) Gas is converted into mmboe using the Society of Petroleum Engineers approved conversion factor of 5658.53 scf/boe

www.energean.com

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END

UPDZMGMRVKZGRZM

RNS Number : 5903Z
Energean Oil & Gas PLC
03 September 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

PMELLFILAFIVIIT

RNS Number : 5931Z
Energean Oil & Gas PLC
03 September 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBBGDCRGGBGIX

RNS Number : 7564Z
Energean Oil & Gas PLC
04 September 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

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END

PMELLFVEAEISIIT

RNS Number : 7569Z
Energean Oil & Gas PLC
04 September 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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END

APMBUGDCGSGBGIS

RNS Number : 2314A
Energean Oil & Gas PLC
10 September 2018

For immediate release
Monday, 10 September 2018

Energean Oil & Gas plc
("Energean" or the "Company")

US Under Secretary of Energy visits Energean's facilities, offshore Greece

On Sunday, September 9, 2018, Energean (LSE: ENOG) was pleased to host the Honourable Mr. Mark Menezes, the U.S. Department of Energy Under Secretary of Energy, at its offshore facilities in Kavala, Eastern Macedonia, Greece.

The U.S. Delegation was given a tour of the Prinos Oil Field platforms and the Energean owned Energean Force drilling rig, currently drilling an extended reach well into the Epsilon Oil Field, and the GSP Jupiter jack up rig, which is currently drilling the first of three vertical development wells in the Epsilon Oil Field.

After concluding his visit to Prinos, Under Secretary Mark Menezes said:

"Achieving energy security for each of our respective countries is made possible by doing everything we can to embrace energy diversity. The Trump Administration, Secretary Perry, and the U.S. Department of Energy support more robust energy, economic, and security ties with Greece, with southeast Europe, and with the entire continent because a strong, vibrant Trans-Atlantic relationship is vital for all of our nations."

Mr. Dimitris Gontikas, Vice President and Managing Director of Energean Greece, said:

"It was a great honour to host Under Secretary Menezes and his distinguished company at Greece's sole hydrocarbon producing facilities which are owned and operated by Energean, and which have an excellent HSE record. We are proud that through our investment in Prinos Oil Field rejuvenation, our Company has led the way towards a new era in Greece's hydrocarbon history, and supported the Greek State in its decision to expand E&P activity in new areas in Western Greece, the Ionian Sea and offshore Crete."

Enquiries

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Georgia Edmonds
Owen Roberts

About Energean Oil & Gas plc

Energean is a London Premium Listed independent E&P company focused on the Eastern Mediterranean region, where it operates in offshore Israel, Greece and the Adriatic and holds 13 licences. Energean has 349 mmboe of 2P reserves and 48 mmboe of 2C resources across its portfolio.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25 year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

1) Gas is converted into mmboe using the Society of Petroleum Engineers approved conversion factor of 5658.53 scf/boe

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END

NRAFKCDKKBKBCCK

RNS Number : 4813A
Energean Oil & Gas PLC
12 September 2018

Energean Oil & Gas plc
("Energean" or the "Company")

Results For Half Year Ended 30 June 2018 London, 12 September 2018 - Energean Oil and Gas plc (LSE: ENOG), the independent oil and gas exploration and production company focused on the Eastern Mediterranean, announces its half-year results for the half year ended 30 June 2018 ("1H 2018").

Mathios Rigas, Chief Executive, Energean Oil & Gas commented:
"During the period we made substantial progress in de-risking our flagship Karish and Tanin development project. We signed a lump-sum, turnkey EPCIC contract with TechnipFMC, simplifying project management and reducing our financial risk exposure, and secured $12 billion of future revenue by signing 12 firm Gas Sales Agreements to deliver a total of 4.2 bcm/yr. Over the next 18 months we aim to prove up sufficient resource to fill the 3.8 bcm/yr of spare capacity in our Karish FPSO, delivering significant incremental value to our stakeholders. Our independent reserves auditor has identified 7.5 Tcf of Israeli prospective resource with a high geological probability of success, which gives us confidence that we can meet this target whilst adhering to our exploration strategy to target resource that can be quickly and economically monetised. We look forward to the results from the Karish North exploration well in 2Q 2019."

Operational and Financial highlights

- Raised $460 million through Premium London Stock Exchange IPO, the largest Oil & Gas IPO for nearly four years.
- Arranged $1,275 million of project financing with an attractive estimated average margin of 4%.
- Took Final Investment Decision for Karish-Tanin in March 2018; on track to deliver first gas in 1Q 2021.
- Increased net 2P reserves to 349 mmboe, a more-than-six times increase versus the 51 mmboe identified at the point of Listing.
- Identified 7.5 Tcf of gross prospective resources offshore Israel with a high geological chance of success.
- Committed to the high impact Karish North exploration well, commencing 1Q 2019 and targeting 1.3 Tcf and 16 million bbls of gross recoverable prospective resource (Energean 70%) with a volume weighted geological chance of success of 69%.
- Delivered 3,801 bopd of production, a 50% increase versus the comparable period for 2017.
- Drilled an Extended Reach Horizontal well into Prinos North; well contributed > 1,000 bopd in 1H 2018.
- Reduced production costs by 27% to $19/bbl (1H 2017: $26/bbl); costs per barrel forecast to reduce further.

	1H 2018 $m	1H 2017 $m	Change
Sales revenue[1]	26.3	26.8	(1.9%)
Operating profit / (loss)	10.2	(7.9)	(229.1%)
Profit / (loss) before tax	82.1	(4.4)	(1,965.9%)
Adjusted EBITDAX[1]	16.7	8.0	108.9%
Operating cash flow[2]	16.9	16.0	5.6%
Cash capex[3]	136.4	26.0	424.6%
Net debt / (cash)	(166.5)	59.4	(380.3%)

1. 1H 2018 revenue includes sale of one versus two cargoes sold in the equivalent period in 2017; increased production in the period is reflected in the increase of inventory. The sales volume impact, due to timing of cargoes in the first half of the year, is offset by higher realised pricing; in 1H 2018 Energean achieved an average sales price of $57.7/bbl (1H 2017: $43.5/bbl). Adjusted EBITDAX is defined on Page 11.
2. After working capital movements
3. Before acquisitions and disposals

4Q18 Outlook

- 2018 Full Year production guidance narrowed to 4,000 - 4,250 bopd (previously 4,000 - 4,500 bopd) due to replacement of Prinos infill drilling with the Epsilon Extended Reach Well. Energean expects production to grow to more than 10,000 bopd by 2021.
- First steel cut on the FPSO hull.
- Complete planning for Karish North exploration well.
- Early production from the Epsilon field via the Extended Reach Well.
- Drilling of one vertical well and commencement of a second at Epsilon.
- Continue early stage seismic operations
- Secondary listing on the Tel Aviv Stock Exchange.

Enquiries
Energean **Tel: 07917 608645**
Kate Sloan, Head of IR

Camarco (Financial PR) **Tel: 020 3757 4980**

A presentation to analysts will be held at 09:30am today at the offices of Stifel Nicolaus. Conference call details are provided below. The presentation slides will be available on the website as soon as possible after the event.

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United Kingdom Toll: +44 3333000804

Israel Toll: +972 37207697

Israel Toll-Free: 1809213407

Greece Toll: +30 21121111509

Greece Toll-Free: 0080033153417

PIN: 54065548#

Chairman's Statement

Simon Heale, Chairman of Energean Oil & Gas, said:

March 2018 marked Energean's admittance to the Premium Listing Segment of the London Stock Exchange with subsequent entry to the FTSE 250 following June's index review. We are very pleased with the response we have had from the investment community and are pursuing a secondary listing on the Tel Aviv Stock Exchange in the months ahead, further expanding the accessibility of our East Mediterranean Oil & Gas story to a wider pool of investors.

Your Board is confident that Energean will continue to deliver value for shareholders by focusing on operational excellence, effective project delivery, risk mitigation and disciplined capital allocation, all guiding principles of Energean's management strategy. Whilst continuing to focus on delivering our flagship Karish and Tanin development on time and on budget, we will continue to assess both organic and inorganic growth opportunities that we believe will deliver value to all of our stakeholders.

On behalf of the Board, I would like to thank the Management Team and all of our colleagues for their hard work in delivering the results and progress that are set out in this report and to thank our new and existing shareholders for their continued support. We look forward to the rest of the year and beyond with confidence.

Operational Review

Israel

Karish and Tanin Development

Energean sanctioned the 2.4 Tcf (gross, Energean 70%) Karish and Tanin development in March 2018. Operations are progressing in line with expectations and the development remains on track for first gas in 1Q 2021, the first delivery milestone being first steel cut on the FPSO before 2018 year end. To date, Energean has contracted gas sales of 4.2 bcm/yr, leaving 3.8 bcm/yr of spare capacity in its FPSO for the monetisation of future discoveries. Over the next 18 months, Energean aims to fill this capacity and believes this should deliver significant additional value for all of our stakeholders.

Reserves and resources

Post-period end, the August 2018 NSAI CPR has approved the conversion of 2.2 Tcf of contingent resources into 2P reserves. 0.2 Tcf of gas relating to the B sands remains within the contingent category. Advancement of the B unit volumes into reserves is dependent on demonstration of commercial deliverability and connected volume to development wells, which should be achieved through testing one or more of the wells.

Contracting structure and critical path items

Energean has contracted TechnipFMC under a turnkey, lump sum EPCIC contract to provide the full suite of FPSO and SURF services during the construction phase. Energean believes that this contracting structure is a key contributor to risk mitigation and that, by minimising contractor interfaces, project management will be simplified.

Technip has subcontracted COSCO to provide the FPSO hull, which will be built at the Fabricator yard in Zhoushan, China. Steel cut is expected by year-end 2018; Energean believes that this is a key milestone to demonstrate that the project is on track. Energean has chosen a new-build FPSO based on an existing design and will adopt a spread moored system, which it believes reduces technical risk on the field. Hull completion is expected to take 12 months. The hull will then travel to the Sembcorp Admiralty Yard in Singapore for installation of the Siemens-built topsides. Energean expects the FPSO to sail away from Singapore in late 2020 ahead of first gas in 2021.

Stena and Halliburton have been selected to provide drilling services, and Wood Group will provide operations and maintenance services once production has commenced.

Gas sales agreements

Energean has executed firm contracts to sell 4.2 bcm/yr of gas into the Israeli domestic market. The contracts have been signed at an average duration of 16 years and an average price of $4.1/mcf (floor $4.0/mcf). The take-or-pay component averages 75%. Energean has an additional contract option with Dalia to sell up to 0.7 bcm/yr.

Energean continues to engage with buyers in the domestic Israeli market and believes that growing demand should result in additional gas sales opportunities that can be leveraged if more gas is discovered. The Company believes that the plan to transfer IEC stations into the private sector offers an opportunity to engage in a competitive sales process with Tamar and Leviathan to enter into long term sales contracts with ex-IEC stations. Energean is also able to consider export markets for any future gas discoveries and has offered sales of 0.5 to 0.8 bcm/yr to Cyprus via a pipeline that could be installed by the early 2020s.

Prospective resources

Energean received an updated CPR for its Israeli acreage in August 2018 from its independent reserves auditors, NSAI. This was the first independent assessment of the new Blocks awarded in the recent offshore licensing round. The CPR recognises gross recoverable prospective resources of 212 bcm (7.5 Tcf) of gas and 101 million barrels of liquids (Energean 70%) and covers both the Karish and Tanin leases alongside the five new exploration Blocks. The results of the updated CPR are consistent with Energean's view that its acreage contains a number of attractive near-field prospects where potential discoveries can be quickly and economically monetised. The Karish FPSO is being built with gas production and

processing capacity of 8 bcm/yr, which Energean aims to fill over the next 18 months. Energean Israel (Energean 70%) has sold 4.2 bcm/yr of discovered gas volumes, leaving 3.8 bcm/yr of available FPSO capacity for the potential tie-back of future discoveries.

Israel Prospective Resource Summary	Gas	Liquids	Geological probability of success
	Bcf	Mmbbls	%
Karish Field			
Deep	9.0	7.0	22
East Block	504.3	7.6	70
Main Block	647.9	8.0	62
North Downthrown Block	440.9	5.8	64
North Upthrown Block	673.5	8.6	73
Northeast Block	219.4	2.0	69
Tanin Field			
Deep	48.3	37.8	20
Prospect 1	250.6	1.3	80
Prospect 2	66.0	0.3	81
Prospect 3	79.0	0.4	81
Licence 12			
Apollo	77.7	0.4	72
Athena East	285.6	1.4	76
Athena West	85.2	0.4	75
Hera	254.4	1.3	75
Hestia	36.7	0.2	68
Zeus	413.2	2.0	75
Licences 21/22/31			
Ares	267.2	1.3	58
Artemis	70.4	0.3	58
Demeter	177.9	0.9	58
Hermes	1,015.9	5.0	56
Orpheus Northeast	204.2	1.0	58
Orpheus Southwest	144.0	0.7	50
Poseidon	616.8	3.0	57

Exploration drilling

In June 2018, Energean made the decision to drill the Karish North prospect with a planned spud date before the end of March 2019, subject to necessary approvals. Karish North is located within Energean's Karish lease and will be drilled immediately prior to the three development well programme that will target Karish Main. In the success case, Karish North is expected to take 45 days to drill and is budgeted at $25 million. The well will be completed as a potential producer in the event a discovery is made with a view to tie back to the Karish FPSO in the future.

The August 2018 NSAI CPR estimated that Karish North contains 1.3 Tcf of gross recoverable prospective resources (Energean 70%). In a success case, additional volumes could i) further underpin existing gas sales contracts; ii) justify additional gas sales volumes; and/or iii) enable Energean to delay Tanin development, replacing $700 million of capital expenditure currently planned for 2024-2025 with tie-back costs of just $100 million.

Following commitment of Karish North Energean has six remaining slots in the Stena drilling contract. The August 2018 CPR identified 7.5 Tcf plus 101 million barrels of gross recoverable prospective resources. Post the drilling of Karish North this leaves a further 6.2 Tcf plus 85 million barrels of gross prospective resource that could be targeted by further exploratory drilling.

Greece

Prinos, Prinos North

Working interest production from Greece averaged 3,801 boepd, an increase of 50% versus the comparable period in 2017 (1H 2017: 2,534 boepd) and in line with expectations. The year-on-year uplift is primarily due to successful management of asphaltene precipitation and continued execution of the development drilling programme. Nine of 25 planned development wells have been drilled to date and the field currently produces from eleven wells, supported by four injectors. Energean is narrowing its Full Year 2018 production guidance to 4,000 - 4,250 bopd (from 4,000 - 4,500 bopd previously), as it has replaced previously planned Prinos infill drilling with the Epsilon Extended Reach well, which impacts timing of production delivery.

In 1H 2018 Energean delivered average production costs of $19 per barrel (1H 2017: $26); the year-on-year reduction reflects increased production against a broadly fixed cost base. Energean expects production cost for the full year 2018 to average approximately $17-19 per barrel, with further reductions expected as production from the Prinos Area grows.

In 1H 2018, Energean drilled an Extended Reach c.4000m horizontal well in the Prinos North satellite to exploit attic oil. This well produced at an average rate of over 1000 boepd in 1H 2018.

In July 2018 Energean discovered oil pay intervals in the deeper Kazaviti and D horizons in the PA-32 well, which was drilled into a central field location. Based on well logs, both reservoir units were predicted to be of low permeability (<5 mD) and discrete well tests were unable to establish a flow to surface. Oil was subsequently seen and sampled at the PA-32 wellhead immediately prior to perforating operations on the shallower B-reservoir.

As at 1 January 2018 Prinos and Prinos North contained 2P reserves of 21.7 mmboe and 2C resources of 23.8 mmboe. Energean has commissioned an updated CPR for its Greek assets for the end of 2018.

Epsilon

Drilling started at the Epsilon (Energean 100%) development project in July 2018. The initial development was planned to

consist of three vertical production wells tied into a new unmanned jacket, Lamda, which is currently being built in the Constanza yard in Romania. A further three-to-five vertical production wells will be drilled in later years to fully exploit the field reserves. First production from the Epsilon vertical well development is expected late 2019; delivery of the Lamda platform is the critical path item.

An additional early production extended reach well, EA-H3, spudded in late July 2018, and is being drilled into the Epsilon accumulation from the Prinos Alpha platform. This well will accelerate first production to 2H 2018 and will drawdown the reservoir pressure, allowing subsequent Epsilon wells to identify flow units and connectivity within the reservoir sands.

As of 1 January 2018 Epsilon contained 2P reserves of 18.4 mmbbls and production is included within the NSAI CPR forecast 1P and 2P profiles. The updated CPR, commissioned for end of 2018, will include a revised view on Epsilon reserves, taking the updated development programme into account.

Katakolo

Energean's Katakolo development contains independently certified 2P reserves of 10.5 mmbbls (Energean: 100%). The asset is held as a 25 year production licence with no outstanding commitments.

Energean has started the environmental and social impact assessment, which it expects to submit during 4Q 2018. Either Final Investment Decision or a farm-down will follow approval of the environmental and social impact assessment; Energean will proceed with the option that delivers the most value for shareholders. If Final Investment Decision is taken in 4Q 2018, first oil will be in 2020. Gross capex for the development is estimated at $60 million.

Exploration

Western Greece

Energean farmed down its position in the Aitoloakarnania and Ioannina Blocks to Repsol in March 2017, reflecting the company's disciplined approach to managing exploration risk. Repsol took a 60% interest in, and operatorship of, the assets and will pay 90% of the costs of upcoming seismic work, capped at $49.9 million.

NSAI's August 2017 CPR included best estimate unrisked prospective resources of 103.3 Bcf of natural gas and 187.1 million barrels of liquids for Energean's Western Greece acreage.

New Ventures

Montenegro

Energean was awarded Blocks 30 and 26, offshore Montenegro, in March 2017. Over 4Q 2018 and 1H 2019, Energean plans to acquire a new 3D seismic survey to improve the seismic imaging and help de-risk the trap definition, whilst also satisfying the commitments associated with the first exploration phase. Energean expects this first exploration phase to cost less than $5 million, in line with its strategy to minimise commitments across its exploration portfolio. ENI has entered into four neighbouring blocks to those held by Energean. Energean believes that ENI's commitments include the drilling of one exploration well, which has the potential to de-risk the Energean acreage.

M&A Opportunities

Energean Management continues to look at inorganic growth opportunities within the East Mediterranean region. All opportunities are considered within our key guiding principle of disciplined capital allocation to ensure that Energean delivers maximal value for all key stakeholders.

HSE

Energean experienced two Lost Time Incidents (LTIs) on the Energean Force during April 2018. The severity of these LTIs was medium and caused no irreversible damage. No LTIs were experienced in other months in the first half.

No environmental incidents occurred during 1H 2018 and Energean recorded good environmental performance. Environmental KPIs in 1H 2018 were within the expected range, demonstrating lower (better) specific values for greenhouse gas emissions, specific energy consumption and specific water consumption versus those recorded in 2017.

During the first half of 2018 Energean received the Approved Environmental Terms for the Prinos Development Project and the consent of the Environmental Scoping Report for the West Katakolo Development.

Outlook

Energean expects an active 18 months ahead. In Israel, it is on track with its Karish Main development with no change to the expectation that first steel will be cut before year end. Development drilling is expected to start in 1H 2019. Energean will soon look to start proving up additional hydrocarbons that can be easily monetised as evidenced by the planned spud of the Karish North exploration well before the end of 1Q 2019. In Greece, it will continue to focus on optimising production. The forward work programme is currently being finalised; well phasing and contribution will be the key drivers of 2019 production levels. Further guidance will be provided in early 2019. Finally, Energean will also continue to evaluate M&A opportunities that it believes to be value accretive to all stakeholders.

Financial Review

Financial results summary

	1H 2018	1H 2017	Change
Working interest production (kboe)	688	459	50.0%
Av. daily working interest production (boed)	3,801	2,534	50.0%
Sales revenue ($m)	26.3	26.8	(1.9%)
Realised Oil Price ($/boe)	57.7	43.5	32.6%
Cost of production[4] ($m)	13.2	12.0	10.0%
Cost of production per barrel ($/boe)	19.4	26.3	(26.2%)
Adjusted EBITDAX[5] ($m)	16.7	8.0	108.8%
Cash flow from operating activities ($m)	16.9	16.0	5.6%
Cash capex[6] ($m)	136.4	26.0	424.6%

	1H 2018	FY 2017	Change
2P reserves[7] (million bbls)	349	51	584.3%
2C resources[7] (million bbls)	48	250	(80.8)%
Net debt (cash) ($m)	(166.5)	75.6	(320.1%)
Net debt / equity (%)	(16.0)	26.2	(161.1%)

4. Cost of sales before inventory movements and depreciation.

5. Page 11 defines Adjusted EBITDAX, which Energean uses as a core business KPI.

6. Before acquisitions and disposals.

7. 2P and 2C numbers reflect the reclassification from the August 2018 NSAI Competent Persons' Report.

Revenue, Production and commodity prices

Working interest production from Greece averaged 3,801 boepd, an increase of 50% for the period (1H 2017: 2,534 boepd). The increase in production is due to continued management of asphaltene precipitation and progress through the development drilling programme.

Prinos production is sold at a $6.4/bbl discount to Urals Med blend, adjusted for final cargo API. 1H 2018 revenue includes sale of one cargo (417,566 barrels) versus two cargoes (569,134 barrels in total) sold in the equivalent period in 2017; the increased production in the period is reflected in the increase of inventory, representing barrels available for sale, of 270,220 barrels. On 26 July 2018, the company sold a 408,856 barrel cargo with a realised price of $68/bbl.

The sales volume impact, due to timing of cargoes in the first half of the year, is offset by higher realised pricing; in 1H 2018 Energean achieved an average sales price of $57.7/bbl (1H 2017: $43.5/bbl).

Cost of production

Cost of oil production is a non-IFRS measure that is used by the Group as a useful indicator of the Group's underlying cash costs to produce hydrocarbons. The Group uses the measure to compare operational performance period-to-period, to monitor cost and assess operational efficiency. Cost of oil production is calculated as cost of sales, adjusted for depreciation and hydrocarbon inventory movements.

The spare processing capacity in the Prinos infrastructure provides a high level of operational leverage. This has resulted in a 27% reduction in per barrel production costs, from $26.2 in 1H 2017 to $19.2 in 1H 2018. As production grows, Energean expects operating costs to continue to fall, reaching less than $10 /boe if the NSAI 2P production profile were to be achieved. Energean guides to full year operating costs of $17 - 19 /bbl.

Depreciation

Depreciation increased by 61.7% to $13.0 million (1H 2017: $8.0 million) due to increased production and capex invested in Greece. On a per barrel of production basis, this represented a 7.8% increase to $18.9/boe (1H 2017: $17.5/boe) reflecting the increased capex.

Sales, General and Administrative expenses

Energean incurred S, G & A costs of $5.1 million in 1H 2018. This represents a 91% increase versus the comparable period last year (1H 2017: $2.7 million) and is due to the additional staffing and administrative costs caused by the rapid growth of the Group's portfolio, the efforts associated with developing the projects, and additional requirements associated with being a Premium listed entity. For the full year Energean expects S, G & A costs to be between $9m and $10m.

Other income

Other income of $7.5 million includes a reversal of a provision for the Greek tax and transfer pricing penalties relating to fiscal years 2006-2011, which were the subject of an appeal that was ruled in Energean's favour in July 2018.

Finance costs

Financing costs for the period were $6.5 million, and are composed mainly of $7.4 million of interest expenses on the EBRD and RBL facilities secured on Energean's producing Greek assets, offset by capitalised interest of $1.4 million. The decrease versus the previous period (1H 2017: $18.7 million) is associated with the conversion of a shareholder loan to preference shares at the end of 1H 2017.

Derivative financial instruments

The gain on derivative of $96.7 million is a result of the valuation of a derivative financial instrument, measured at fair value at the end of each reporting date, which related to Energean Israel Limited Class B Shares that the Group had a contingent commitment to acquire in the event of an exit (IPO or sale). The methodology used to value the shareholding multiplied the estimated probability of an exit event (IPO or sale) by the estimated difference between the consideration payable and the estimated value of the B shares. The gain recognised in 1H 2018 (1H 2017: $ nil) reflects the increase in probability of an exit event to 100% when Energean listed on the London Stock Exchange on 21 March 2018. Following execution on the contingent commitment the derivative financial asset has been derecognised and transferred to the cost of investment in Energean Israel Limited.

Crude oil hedging

In order to mitigate price risk and take advantage of the April spike in Brent prices, Energean decided to hedge 30% of anticipated sales volumes for 2018. On April 13th, Energean entered a hedging trade with Britannic Trading Limited, selling 150,000 bbls for each of the anticipated 400,000 bbl liftings in July, September and December at an average price of $69.39/bbl.

Hedged quantity bbls	Contract Month	Cargo Month	Cargo Size bbls	Fixed Price $/bbl
150,000	Jun / Jul average	July	408,856	70.73
150,000	Aug / Sept average	September	400,000	69.54
150,000	Nov / Dec average	December	400,000	67.91

Taxation

Energean recorded tax income of $5.3 million in 1H 2018 (1H 2017: $9.1 million tax expense).

Adjusted EBITDAX

Adjusted EBITDAX is a non-IFRS measure used by the Group to measure business performance. It is calculated as profit or loss for the period, adjusted for discontinued operations, taxation, depreciation and amortisation, other income and expenses (including the impact of derivative financial instruments and foreign exchange), net finance costs and exploration costs. The Group presents adjusted EBITDAX as it is used in assessing the Group's growth and operational efficiencies as it illustrates the underlying performance of the Group's business by excluding items not considered by management to reflect the underlying operations of the Group.

	1H 2018 $m	1H 2017 $m
Adjusted EBITDAX	16.7	8.0
Reconciliation to profit / (loss):		
Depreciation and amortisation	(13.0)	(8.0)
Exploration and evaluation expense	(0.6)	(0.2)
Other income/(expense)	7.4	(7.5)
Finance expenses	(6.5)	(18.7)
Finance income	0.4	0.0
Gain on derivative	96.7	-
Net foreign exchange	(18.7)	22.2
Tax	5.3	(9.1)
Profit / (loss) from discontinued operations	-	(1.4)
Profit / (loss) from continuing operations[8]	**87.4**	**(14.9)**

8. Numbers may not sum due to rounding

Operating cash flow

Cash from operations before movements in working capital was $16.5 million, representing a 153% increase on the comparable period (1H 2017: $6.5 million). After adjusting for working capital movements, cash from operations was $16.9m, a 5.6% increase on the comparable period (1H 2017: $16.0 million).

Capex

Cash capex in 1H 2018 amounted to $136.4 million (1H 2017: $26.0 million). $96.3 million was invested in Israel and $40.0 million in Greece.

Energean guides to $470 million of accrued capex for the year. Cash capex will be contingent on payment timing at the end of the year.

Goodwill

Energean has recorded $75.8 million of goodwill (1H 2017: $ nil) in respect of the acquisition of Energean Israel Limited. In accordance with IAS 12, Energean is required to recognise a deferred tax liability in relation to the forward liability assumed, the provision for which is calculated as the tax rate of Israel (23%) multiplied by the difference between the assigned fair value and the tax bases of assets acquired. The offsetting accounting entry to this is goodwill. None of this goodwill will be deductible for tax purposes.

Net cash / debt and gearing ratio

Net debt is defined as the Group's total borrowings less cash and cash equivalents. Management believes that net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of borrowings after taking account of any cash and cash equivalents that could be used to reduce borrowings. The Group defines capital as total equity and calculates the gearing ratio as net debt divided by capital.

Net debt reconciliation	1H 2018 $m	1H 2017 $m	31 December 2017 $m
EBRD facility ($200m)	121.8	73.2	91.3
Israel Project Finance facility ($1,275m)	-	-	-
Total borrowings	**121.8**	**73.2**	**91.3**
Cash and cash equivalents	(288.3)	(13.7)	(15.7)
Total net debt / (cash)	**(166.5)**	**59.5**	**75.6**
Capital	1,038.0	196.8	289.0
Gearing ratio	**(16.0%)**	**30.2%**	**26.1%**

In March 2018, Energean raised $460.0 million through its Premium List IPO. Net of cash transaction costs of $19.5 million this contributed $440.5 million of cash.

EBRD Facility Agreements

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities i) a facility of up to $105 million with EBRD and the Black Sea Trade and Development Bank as lenders; and ii) a $75 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders. Proceeds from the Romanian Club Facility will finance exclusively 85% of the value

attributable to goods and services under the GSP EPCIC. Interest is charged on the $105m component of the loan at LIBOR + 4.9% and on the $75m Romanian facility at LIBOR + 3%.

On 28 February 2018 the Group submitted a request to draw down an amount of $30 million under the RBL Senior Facility Agreement. The drawdown was effected with the conditions precedent being satisfied on 14 March 2018 and was paid to the Group on 23 March 2018.

Karish-Tanin Project Finance

In 1H 2018 Energean secured $1,275 million of senior secured project finance for its Karish-Tanin project. The loan is held at the Energean Israel Limited level (Energean 70%). Once drawn, interest is to be charged at LIBOR + 3.75% over months 1 to 12, LIBOR + 4.00% over months 13 - 24, LIBOR + 4.25% over months 25 - 36 and LIBOR + 4.75% over months 37 - 45. The facility matures in December 2021 and has a bullet repayment on maturity. There is a commitment fee of 30% of the applicable margin. Energean estimates that the weighted average applicable interest rate over the life of the facility will be 4.0%.

Energean expects to start drawing down on the project finance facility in 1H 2019.

Business combination

On 27 March 2018, the Group, following a final investment decision in respect of the Karish and Tanin assets, subscribed for additional shares in Energean Israel for an aggregate consideration of US$266.7 million, payable in cash, increasing its shareholding in Energean Israel to 70% from 50% as Kerogen did not participate in the new share issuance. Upon completion of this subscription, the Group holds 70% of the shares in Energean Israel, with Kerogen Capital holding the remaining 30%. Following the above, Energean Israel is consolidated in Energean's accounts. Energean has applied the acquisition method of accounting as required by IFRS 3. Each identifiable asset and liability has been measured at fair value at the date of acquisition.

Principal risks and uncertainties

Strategic

- Reserve replacement: the Group's long term future success depends on its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable.
- Geopolitical: the geopolitical situation in Israel may adversely affect the Group's business.

Health, Safety and Environmental

- The Group is obliged to comply with health, safety and environmental regulations and cannot guarantee that it will be able to full adherence with these regulations.

Project Execution and Production Operation

- Project execution: the Group's success will be partly dependent upon completing the Karish-Tanin development on budget and on schedule. Whilst the execution strategy has been designed to mitigate this risk as far as possible, any delay in project delivery could have an impact on the Group's Gas Sales and Purchase contracts.
- Production: the Group's success will be partly dependent upon continuing production from Prinos; it is exposed to the effects of disruption, delays or interruptions of production from wells in this area.
- Major cyber or information security incident.

Financial

- Compliance with financial covenants: the Group's loan agreements are subject to restrictive debt covenants and security arrangements that may impact its ability to finance its operations.
- Treasury and trading: the Group is exposed to associated risks surrounding foreign exchange and commodity price risk, although seeks to manage these risks where Management believe necessary.
- Counterparty risks: including exposure to delayed payment, counterparty default or suspension, or termination of sales.

Governance and Compliance

- Fraud, bribery and corruption.

Events since 30 June 2018

In August 2018, Energean's independent reserves auditor, NSAI, issued a report that covered the Karish and Tanin fields and the five blocks awarded as part of the recent offshore licencing round. 2.2 Tcf of gas and 31.8 million bbls of liquids (gross, Energean 70%) have been converted from contingent resources to 2P reserves, increasing Energean's net 2P reserves from 51 million boe at the point of IPO to 349 million boe. 0.2 Tcf of gas resource and 1 million bbls of liquids in Israel remain in contingent resources, contributing to an overall net company figure of 48 million boe. NSAI also estimated gross unrisked prospective resources of 7.5 Tcf of gas and 101 million bbls of liquids across the Karish and Tanin leases and the five new exploration licences.

Going concern

The Company monitors its funding position and its liquidity risk throughout the year to ensure it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on the Company's latest production and expenditure forecasts, management's best estimates of future commodity prices (based on Gas Sales Agreements, forward curves, adjusted for the Company's hedging programme) and the Company's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, changes in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and to enable management to formulate appropriate and timely mitigation policies.

At 30 June 2018, Energean Israel was yet to draw down on the project financing facility that will fund the Karish-Tanin development offshore Israel, and Energean retained sufficient liquidity within the Reserve Based Lending Facility that is funding development activity at Prinos, Prinos North and Epsilon in Greece. Energean retains sufficient financial headroom on the covenant restrictions contained within the various financing facilities, and the Company's forecasts show that this will be maintained for at least the 12 months following the approval of the 2018 Interim Report and Accounts.

The Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future, and continue to adopt the going concern basis of accounting in preparing these consolidated interim financial statements.

Statement of Directors' responsibilities

The Directors confirm that to the best of their knowledge:

1) The condensed set of financial statements has been prepared in accordance with IAS 34 'Interim Financial Reporting';

2) The interim management report contains a fair review of the information required by FTR 4.2R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year);

3) The interim management report includes a true and fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

Mathios Rigas	**Panos Benos**
Chief Executive Officer	Chief Financial Officer
11 September 2018	11 September 2018

Disclaimer

This report may contain forward-looking statements and information that both represents management's current expectations and beliefs and are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business and with any statement about the future.

Whilst Energean believes that such expectations and beliefs are reasonable in the light of the information available at this time, the actual outcomes may be materially different from the said statements, owing to factors beyond Energean's knowledge or control (or within Energean's control where, for example, the Company decides on a change in strategy).

Energean undertakes no obligation whatsoever to revise any such forward looking statements to reflect any changes (in expectations, beliefs, or circumstances, events, the Group's plans or strategy or otherwise). Accordingly, no reliance may be placed on such forward looking statements or any figures therein.

INDEPENDENT REVIEW REPORT TO ENERGEAN OIL & GAS plc

Introduction

We have been engaged by the Company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2018 which comprises the consolidated income statement, the consolidated statement of comprehensive income, the consolidated statement of financial position, the consolidated statement of changes in equity, the consolidated statement of cash flows and notes 1 to 28. We have read the other information contained in the half yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

This report is made solely to the company in accordance with guidance contained in International Standard on Review Engagements 2410 (UK and Ireland) "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company, for our work, for this report, or for the conclusions we have formed.

Directors' Responsibilities

The half-yearly financial report is the responsibility of, and has been approved by, the directors. The directors are responsible for preparing the half-yearly financial report in accordance with the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

As disclosed in note 2, the annual financial statements of the group are prepared in accordance with IFRSs as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", as adopted by the European Union.

Our Responsibility

Our responsibility is to express to the Company a conclusion on the condensed set of financial statements in the half-yearly financial report based on our review.

Scope of Review

We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410, "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

INDEPENDENT REVIEW REPORT TO ENERGEAN OIL & GAS plc (continued)

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2018 is not prepared, in all material respects, in accordance with International Accounting Standard 34 as adopted by the European Union and the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

Andrew Smyth
Senior Statutory auditor
for and on behalf of Ernst & Young LLP
London
11 September 2018

Condensed Consolidated Income Statement
Six months ended 30 June 2018

		6 months ended 30 June (Unaudited)	
		2018	2017
		$'000	$'000
Consolidated income statement	**Notes**		
Revenue	5	26,257	26,754
Cost of Sales	6a	(17,775)	(24,254)
Gross profit/(loss)		**8,482**	**2,500**
Administration expenses	6b	(4,835)	(2,482)
Selling and distribution expenses	6c	(218)	(170)
Exploration and evaluation expenses	6d	(609)	(239)
Other income / (expense)	6e	7,393	(7,530)
Operating profit/(loss)		**10,213**	**(7,921)**
Finance Income			

		406	7
Finance Costs	7	(6,508)	(18,714)
Gain on derivative	8	96,709	-
Net foreign exchange gain/(loss)		(18,742)	22,205
Profit/(loss) from continuing operations before tax		**82,078**	**(4,423)**
Taxation income / (expense)	9	5,322	(9,099)
Profit/(loss) from continuing operations		**87,400**	**(13,522)**
Net Results from discontinued operations	10	-	(1,403)
Profit/(loss) for the period		**87,400**	**(14,925)**
Attributable to:			
Owners of the parent		90,069	(14,916)
Non controlling Interests		(2,669)	(9)
		87,400	**(14,925)**
Basic and diluted earnings/(loss) per share (cents per share)			
From continuing operations	11	**$0.81**	**($0.19)**
From total earnings	11	**$0.81**	**($0.21)**

Condensed Consolidated Statement of Comprehensive Income
Six months ended 30 June 2018

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
Consolidated statement of comprehensive income		
Profit/(loss) for the year	87,400	(14,925)
Other comprehensive income:		
Items that may be reclassified subsequently to profit or loss		
Cash Flow Hedge, net of tax		

	(2,823)	-
Exchange difference on the translation of foreign operations, net of tax	107	(2,746)
Other comprehensive income/(loss) after tax	**(2,716)**	**(2,746)**
Total comprehensive income/(loss) for the period	**84,684**	**(17,671)**
Total comprehensive income/(loss) attributable to:		
Owners of the parent	87,353	(17,662)
Non-controlling Interests	(2,669)	(9)
	84,684	**(17, 671)**

Condensed Consolidated Statement of Financial Position
Six months ended 30 June 2018

	Notes	As at 30 June (Unaudited) 2018 $'000	As at 31 December 2017 $'000
ASSETS			
Non-current assets			
Oil & Gas properties	12	908,038	248,895
Other property, plant and equipment	12	67,004	61,081
Exploration and evaluation assets	13	5,473	3,350
Goodwill	4	75,800	-
Other intangible assets	13	551	650
Other receivables	17	47,081	591
Deferred tax asset	14	12,704	13,473
Bank deposits	15	3,838	1,899
		1,120,489	329,939
Current assets			
Inventories	16	18,680	9,529

Trade and other receivables	17	55,898	24,684
Cash and cash equivalents	15	284,422	13,793
Derivative asset	8	-	93,292
		359,000	141,298
Total assets		**1,479,489**	**471,237**
EQUITY AND LIABILITIES			
Equity attributable to owners of the parent			
Share capital	18	2,062	917
Share premium		662,904	-
Equity reserves		(7,898)	62,323
Share based payment reserve	24	608	-
Merger reserves		139,903	139,903
Retained earnings		14,782	(138,455)
Equity attributable to equity holders of the parent		**812,361**	**64,688**
Non-controlling interests	19	225,425	224,294
Total Equity		**1,037,786**	**288,982**
Non-Current Liabilities			
Borrowings	20	121,783	78,831
Deferred tax liabilities	14	78,691	3,570
Retirement benefit liability	21	3,219	3,288
Provisions	22	6,437	5,688
Other payables	23	69,582	2,544
		279,712	93,921
Current Liabilities			
Trade and other payables	23	155,867	66,528
Borrowings	20	-	12,500
Provisions	22	6,124	9,306
		161,991	88,334
Total Liabilities		441,703	182,255

Total Equity and Liabilities	**1,479,489**	**471,237**

Approved by the Board on 11th September 2018

Matthaios Rigas — Chief Executive Officer

Panos Benos — Chief Financial Officer

Condensed Consolidated Statement of Changes in Equity
Six months ended 30 June 2018

	Share Capital $'000	Share Premium[1] $'000	Other Reserve[2] $'000	Share based payment reserve[3] $'000	Translation Reserve[4] $'000	Retained earnings $'000	Merger reserves $'000	Total $'000	Non Controlling Interests $'000	Total $'000
At 1 January 2017	**14,904**	**125,851**	**404**	**-**	**(9,175)**	**(148,407)**	**-**	**(16,423)**	**303**	**(16,120)**
Loss for the period	-	-	-	-	-	(14,916)	-	(14,916)	(9)	(14,925)
Exchange difference on the translation of foreign operations	-	-	-	-	(2,746)	-	-	(2,746)	-	(2,746)
Total comprehensive loss	**-**	**-**	**-**	**-**	**(2,746)**	**(14,916)**	**-**	**(17,662)**	**(9)**	**(17,671)**
Transactions with owners of the company										
Group restructuring (Note 18)	(14,052)	(125,851)	-	-	-	-	139,903	-	-	-
Transaction with non controlling interests	-	-	6,564	-	-	-		6,564	224,000	230,564
Issuance of shares	65	-	-	-	-	-	-	65	-	65
At 30 June 2017	**917**	**-**	**6,968**	**-**	**(11,921)**	**(163,323)**	**139,903**	**(27,456)**	**224,294**	**196,838**

Condensed Consolidated Statement of Changes in Equity
Six months ended 30 June 2018

	Share	Share	Other	Share based payment	Translation	Retained	Merger		Non Controlling

	Capital $'000	Premium[1] $'000	Reserve[2] $'000	reserve[3] $'000	Reserve[4] $'000	earnings $'000	reserves $'000	Total $'000	Interests $'000	Total $'000
At 1 January 2018	**917**	**-**	**73,750**	**-**	**(11,427)**	**(138,455)**	**139,903**	**64,688**	**224,294**	**288,982**
Profit for the period	-	-	-	-	-	90,069	-	90,069	(2,669)	87,400
Retrospective application of IFRS 9 (note 2.1)	-	-	-	-	-	(4,337)	-	(4,337)		(4,337)
Cash flow hedge, net of tax	-	-	(2,823)	-	-	-	-	(2,823)	-	(2,823)
Exchange difference on the translation of foreign operations	-	-	-	-	107	-	-	107	-	107
Total comprehensive income	**-**	**-**	**(2,823)**	**-**	**107**	**85,732**	**-**	**83,016**	**(2,669)**	**80,347**
Transactions with owners of the company		-	-	-				-		-
IPO shares	1,016	462,101	-	-	-	-	-	463,117	-	463,117
Transaction cost in relation to IPO and new share issue	-	(23,068)	-	-	-	-	-	(23,068)	-	(23,068)
Share plan reserves	-	-	-	608	-	-	-	608	-	608
Derecognition of derivative asset (Note 8)	-	-	(67,505)	-	-	67,505	-	-	-	-
Advances for shares	-	-	-	-	-	-	-		23,000	23,000
Transaction with non controlling interests (note 19)	129	223,871	-	-	-	-	-	224,000	(224,000)	-
NCI on acquisition of subsidiary	-	-	-	-	-	-	-	-	204,800	204,800
At 30 June 2018	**2,062**	**662,904**	**3,422**	**608**	**(11,320)**	**14,782**	**139,903**	**812,361**	**225,425**	**1,037,786**

[1] The share premium account represents the total net proceeds on issue of the Company's shares in excess of their nominal value of 0.01p per share less amounts transferred to any other reserves.

[2] Other reserve is used to recognise remeasurement gain or losses on cash flow hedge and actuarial gain or losses from defined retirement benefit plan. Furthermore, other reserve was used to recognise measurement gain from derivative asset, refer to note 8 for further detail of this transaction

[3] The share-based payments reserve is used to recognise the value of equity-settled share-based payments provided to employees, including key management personnel, as part of their remuneration. Refer to note 24 for further details of these plans.

[4] The foreign currency translation reserves is used to record unrealised exchange differences arising from the translation of the financial statements of entities within the Group that have a functional currency other than US dollars.

[5] Refer to note 18

Condensed Consolidated Statement of Cash Flows
Six months ended 30 June 2018

	Note	6 months ended 30 June (Unaudited) 2018 $'000	2017 $'000
Operating activities			
Profit/(loss) from continuing operations before tax		82,078	(4,423)
Loss from discontinued operations		-	(1,403)

Profit / (loss) before taxation		**82,078**	**(5,826)**
Adjustments to reconcile profit/(loss) before taxation to net cash provided by operating activities:			
Depreciation, depletion and amortisation	12,13	13,229	8,177
Impairment loss on inventory		-	39
Gain from disposal of subsidiary		-	(1,540)
(Decrease)/increase in provisions		(7,243)	9,153
Finance income		(406)	(6)
Finance costs	7	6,508	18,714
Fair value gain on derivative	8	(96,709)	-
Share-based payment charge	24	252	-
Net foreign exchange gain/(loss)		18,742	(22,205)
Cash flow from operation before working capital adjustments		16,451	6,506
(Increase)/decrease in inventories		(9,418)	1,570
(Increase)/decrease in trade and other receivables		2,912	201
(Decrease)/increase in trade and other payables		6,970	7,698
Net cash from / (used in) operating activities		16,915	- 15,975
Investing activities			
Payment for purchase of property, plant and equipment		(134,882)	(24,519)
Payment for purchase of intangible assets		(1,508)	(1,522)
Disposal of subsidiary, net of cash disposed		-	(5,610)
Acquisition of a subsidiary, net of cash acquired	4	(32,746)	-
Interest received		406	6
Net cash used in investing activities		(168,730)	(31,645)
Financing activities			
Proceeds from issue of share capital		460,000	-
Proceeds from new debt		34,085	16,250
Proceed from share capital increase in subsidiary		23,000	-
Transaction costs in relation to IPO and new share issue		(19,459)	-
Debt arrangement fees		(52,277)	-
Finance costs paid		(9,646)	(3,613)

Net cash from financing activities		435,703	12,637
Net increase / (decrease) in cash and cash equivalents		283,888	(3,033)
Cash and cash equivalents:			
At beginning of the period		15,691	17,587
Effect of exchange rate fluctuations on cash held		(11,319)	(815)
At end of the period	15	288,260	13,739
Non-current bank deposits		3,838	1,660
Current cash and cash equivalents		284,422	12,079
Total cash and cash equivalents at end of the period	15	288,260	13,739

Supplemental cash flow information:

Non-Cash Investing and Financing Activities for the period ended

Investment in petroleum and gas assets against liabilities		67,525	-
Loan capitalisation and issuance of preference shares	19	-	230,564
Capitalisation of depreciation to oil & gas properties	12	1,279	1,145
Capitalised borrowing costs	12	1,386	647
Costs related to debt not yet drawn down		2,167	-

Notes to the Condensed Interim Consolidated Financial Statements

1. Corporate Information

Energean Oil & Gas plc (the 'Company') was incorporated in England & Wales on 8 May 2017 as a public company with limited liability, under the Companies Act 2006. Its registered office is at 44 Baker Street, London W1U 7AL, United Kingdom. The Company and all subsidiaries controlled by the Company, are together referred to as "the Group".
The Group has been established with the objective of exploration, production and commercialisation of crude oil and natural gas in Greece, Israel, North Africa and the wider Eastern Mediterranean.
On 16 March 2018 the Company acquired the 50% of the preference shares of Energean Israel Limited ("Energean Israel") from its founding shareholders after paying total consideration of $10 million.
On 21 March 2018 the Company completed the admission of its shares to the Premium Segment of the London Stock Exchange.
On 29 March 2018, the Group, following a final investment decision in respect of the Karish and Tanin assets, subscribed for additional ordinary shares in Energean Israel for an aggregate consideration of $266.7 million, payable in cash. Upon completion of this subscription, the Group holds 70% of the shares in Energean Israel, with Kerogen Capital holding the remaining 30% (refer to note 4).
Based on the above, since 29 March 2018 Energean has consolidated Energean Israel Ltd in its consolidated financial statements.

Subsidiaries

Name of subsidiary	Country of incorporation / registered office	Principal activities	Shareholding At 30 June 2018 (%)	Shareholding At 31 December 2017 (%)
Energean E&P Holdings Ltd	36 Vyronos Avenue, 1506 Nicosia Cyprus	Holding Company	100	100
Energean Oil & Gas S.A	32, Kifissias Ave. 151 25 Marousi Athens, Greece	Oil and gas exploration, development and production	100	100
Kavala Oil S.A.	P.O. BOX 8, 64006 Nea Karvali Kavala, Greece	Provision of oil and gas support services	99.92	99.92
Energean International Limited	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	100	100
Energean Israel Limited (Note 4)	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	70	50
Energean Montenegro Limited	36 Vyronos Avenue, 1506 Nicosia Cyprus	Oil and gas exploration, development and production	100	100

The Income Statement and Statement of Comprehensive Income, Statement of Financial Position, Statement of Changes in Equity, Statement of Cash Flows and associated Notes to the Financial Statements for the financial year ended 31 December 2017 included in the 30 June 2018 half yearly financial report do not constitute the Group's statutory accounts, as defined under section 435 of the Companies Act 2006. The Group's statutory financial statements for the financial year ended 31 December 2017 have been audited by the Group's external auditor and filed with Companies House in the United Kingdom. The auditor's opinion on these accounts was unqualified and did not contain a statement under either Section 498(2) or 498(3) of the Companies Act 2006.

The Group's condensed consolidated interim financial statements are unaudited but have been reviewed by the auditors and their report to the Company is included on page 16. These condensed consolidated interim financial statements of the Group for the six months ended 30 June 2018 were approved and authorised for issue by the Board of the Directors on 11th September 2018

2. Basis of preparation

2.1 Basis of preparation

The unaudited condensed consolidated interim financial statements for the six months ended 30 June 2018 included in this interim report have been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting', as adopted by the European Union, and unless otherwise disclosed have been prepared on the basis of the accounting policies set out in the Group's Annual Report for year ended 31 December 2017.
The unaudited condensed consolidated interim financial statements are prepared on a going concern basis as the Directors, having considered available relevant information, have a reasonable expectation that the Group has adequate resources to continue to operate for the foreseeable future.
The consolidated financial statements have been prepared on a historical cost basis and are presented in US Dollars, which is also the Company's functional currency, rounded to the nearest thousand dollars ($'000) except as otherwise indicated.
The US dollar is the currency that mainly influences sales prices and revenue estimates, and also highly affects its operations. The functional currencies of the Group's main subsidiaries are as follows: for Energean E&P Holdings Ltd, Energean Oil & Gas S.A., Kavala Oil SA and Energean Montenegro is Euro, for Energean International Limited and Energean Israel Limited is US$.
Comparative figures for the period to 30 June 2017 and 31 December 2017 are for the period ended on that date. The interim financial statements do not include all the information and disclosures required in the annual financial statements, and should be read in conjunction with the consolidated financial statements in the Energean Oil & Gas plc Annual Report and Accounts for the year ended 31 December 2017. The significant judgements made by management in applying these policies, and key sources of estimation uncertainty are consistent with those followed in the preparation of the Group's financial statements for the year ended 31 December 2017, except for the adoption of the following standards and amendments:

New and amended accounting standards and interpretations
The accounting policies adopted in the preparation of the interim condensed consolidated financial statements are consistent with those followed in the preparation of the Group's annual consolidated financial statements for the year ended 31 December 2017, except for the adoption of new standards effective as of 1 January 2018. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.
The Group applies, for the first time, IFRS 15 Revenue from Contracts with Customers and IFRS 9 Financial Instruments. The adoption of IFRS 15 did not have a significant impact on the Group's consolidated financial statements that requires restatement of previous financial statements.
IFRS 9 Financial Instruments replaces IAS 39 Financial Instruments: Recognition and Measurement for annual periods beginning on 1 January 2018, bringing together two important aspects of the accounting for financial instruments project: classification and measurement, and impairment.
The effect on the Group of adopting IFRS 9 is, as follows:

Loan modification
IFRS 9 changed accounting for loan modifications, which the Group may experience from time to time. According to IFRS 9, an entity shall recognise any adjustment to the carrying amount of a financial liability arising from a modification or exchange in the statement of comprehensive income at the date of the modification or exchange. According to the new requirements:
• The Company recalculated the amortised cost of the intercompany loan in the amount of $192.8 million as at 30 June 2018 between Energean International Limited (Cyprus) and Energean Oil & Gas S.A. (Greece) when the terms modified (31 December 2017).
As a result, intercompany loan liabilities differed from the liabilities under the loan agreements with the subsequent re-measurement of deferred tax.
• The carrying amount of the intercompany balance is eliminated in the Group's consolidated financial statements. The effect of the deferred tax recalculation was recognised in the statement of comprehensive income at the date of the modification or exchange.
The impact of the loan modification on the statement of financial position at the recognition date was the following:

	Balance at 31.12.2017 published $'000	Loan modification under IFRS 9 $'000	Balance at 01.01.2018 $'000
Retained Earnings	(138,455)	(4,337)	(142,792)
Deferred tax liabilities	3,570	4,337	7,907

Several other amendments and interpretations apply for the first time in 2018, but did not have any significant impact on the interim condensed consolidated financial statements of the Group.

3. Segmental Reporting

The information reported to the Group's Chief Executive Officer and Chief Financial Officer (Chief Operating Decision Makers) for the purposes of resource allocation and assessment of segment performance is focused on five operating segments: Greece (including production asset of Prinos and non-producing assets of Ioannina, Katakolo and Aitolokarnania), Israel, Egypt (for the period ended 30 June 2017 included non producing exploration asset of West Kom Ombo), Montenegro (including two non producing exploration assets) and New Ventures.
The Group's reportable segment under IFRS 8*Operating Segments* are Greece and Israel. Segments that do not exceed the quantitative thresholds for reporting information about operating segments have been included in Other.

Segment revenues, results and reconciliation to profit before tax
The following is an analysis of the Group's revenue, results and reconciliation to profit before tax by reportable segment:

	Greece	Israel	Other & intercompany transactions	Total
	$'000	$'000	$'000	$'000
Six months ended 30 June 2018				
Revenue	24,965	-	1,292	26,257
Adjusted EBITDAX	18,466	(615)	(1,193)	16,658
Reconciliation to profit before tax:			-	
Depreciation and amortisation expenses	(13,163)	(7)	(59)	(13,229)
Exploration and evaluation expenses	(18)	-	(591)	(609)
Other income/(expense)	7,475	-	(82)	7,393
Finance income	73	113	220	406
Finance costs	(12,963)	(35)	6,490	(6,508)
Gain on derivative	-	-	96,709	96,709
Net foreign exchange gain/(loss)	(9,541)	(10,973)	1,772	(18,742)
Profit/(loss) before income tax	**(9,671)**	**(11,517)**	**103,266**	**82,078**
Six months ended 30 June 2017				
Revenue	24,964	-	1,790	26,754
Adjusted EBITDAX	7,622	-	403	8,025
Reconciliation to profit before tax:		-	-	
Depreciation and amortisation expenses	(8,156)	-	(21)	(8,177)
Exploration and evaluation expenses	(58)	-	(181)	(239)
Other income/(expense)	(8,557)	-	1,027	(7,530)
Finance income	21,038	-	(21,031)	7
Finance costs	(17,307)	-	(1,407)	(18,714)
Net foreign exchange gain/(loss)	22,103	-	102	22,205
Profit/(loss) before income tax	**16,685**	**-**	**(21,108)**	**(4,423)**

Six months ended 30 June 2018				
Oil & Gas properties	258,110	650,355	(427)	**908,038**
Other property, plant and equipment	66,365	83	556	**67,004**
Intangible assets	4,801	76,481	542	**81,824**
Other assets	81,993	251,707	88,923	**422,623**
Total assets	**411,269**	**978,626**	**89,594**	**1,479,489**

Total liabilities	**410,330**	**231,319**	**(199,946)**	**441,703**
Year ended 31 December 2017				
Total assets	372,636	-	98,601	471,237
Total liabilities	386,035	-	(203,780)	182,255

Segment Cash flows

	Greece	**Israel**	**Other & intercompany transactions**	**Total**
	$'000	**$'000**	**$'000**	**$'000**
Six months ended 30 June 2018				
Net cash from (used in) operating activities	20,619	(136)	(3,568)	16,915
Net cash (used in) investing activities	(45,509)	(96,232)	(26,988)	(168,730)
Net cash from financing activities	23,094	265,206	147,403	435,703
Net increase/(decrease) in cash and cash equivalents	(1,796)	168,838	116,846	283,888
Cash and cash equivalents at end of the period	5,621	160,282	122,357	288,260
Six months ended 30 June 2017				
Net cash from (used in) operating activities	15,291	(985)	1,669	15,975
Net cash (used in) investing activities	(25,844)	(2,715)	(3,086)	(31,645)
Net cash from financing activities	7,799	4,702	136	12,637
Net increase/(decrease) in cash and cash equivalents	(2,754)	1,002	(1,281)	(3,033)
Cash and cash equivalents at end of the period	9,678	-	4,061	13,739

4. Business combination

At 31 December 2017, the Group held a commitment to acquire 50% of the preference shares in Energean Israel Limited. The recognition of this commitment, which represented a derivative financial instrument, was based on management's estimate of the likelihood of the triggering events occurring (upon either a successful Initial Public Offering ("IPO") or in the event of a sale transaction), the estimated valuation of the Israel entity and the $10 million exercise price. The value of the Israel entity was estimated based on the price negotiated at a similar time with Kerogen as a transaction between market participants which drove the subscription price of $266.7 million for the Energean Israel share issuance.

The Group recognised a derivative financial asset of $93.3 million in the 2017 financial statements. On 21 March 2018, the Group successfully completed an IPO on the London Stock Exchange and the probability of IPO taking place by definition became 100%. At that date the Group re-measured the value of the derivative asset, which was valued at $190 million, representing an increase of $96.7 million since the year end, which has been taken to the income statement. Furthermore, the IPO event crystallised the Group's commitment to purchase the Energean Israel preference shares.

The acquisition of 50% of preference shares in Energean Israel, changing the economic interest over the entity, resulted in accounting for the Energean Israel as a 50% Joint Venture. The derivative asset recognised and re-measured on 16 March 2018 was discharged in consideration for the acquisition of the 50% of the entity's preference shares.

On 29 March 2018, the Group, following a final investment decision in respect of the Karish and Tanin assets, subscribed for additional shares in Energean Israel for an aggregate consideration of $266.7 million, payable in cash. Prior to this subscription, Kerogen Capital Limited ("Kerogen") held 50% of the equity voting shares in Energean Israel and did not participate in the new share issuance. Upon completion of this subscription, the Group holds 70% of the shares in Energean Israel, with Kerogen holding the remaining 30%.

From 29 March 2018, Energean Israel has therefore been consolidated into the Group and represents a business combination for which acquisition accounting is required in line with IFRS 3: Business Combinations.

The identifiable assets acquired and liabilities assumed of the acquiree are recognised as of the acquisition date and measured at fair value as at that date. Any non-controlling interest in the acquiree is also recognised at fair value at the acquisition date. The fair value of the business acquired is represented by the Karish and Tanin oil and gas assets, cash and working capital, offset by certain liabilities including the deferred consideration obligation for the oil & gas licences. The fair value allocation, as mentioned above, has been determined by management using the agreement with Kerogen in December 2017 as a transaction between market participants which drove the subscription price of $266.7 million for the Energean Israel share issuance. This resulted in an aggregate fair value of $682.7 million being allocated to the identifiable assets and liabilities acquired, prior to the recognition of a deferred tax liability of $79.0 million as further described below.

The interim condensed consolidated financial statements include the results of Energean Israel for the three month period ended 30 June 2018. Since the acquisition date Energean Israel's loss included in the consolidated statement of comprehensive income

for the reporting period amounted to $8.9 million. If the combination had taken place at the beginning of the year, profit from continuing operations for the period would have been $83.5 million. Post the August 2018 independent Competent Persons Report (CPR), Group's 70% stake in Energean Israel represents 298 mmboe of 2P reserves and 24 mmboe of 2C resources.

The fair values of the identifiable assets and liabilities of Energean Israel have been provisionally estimated as at the date of acquisition and were as follows:

	Fair value recognised on acquisition $'000
Assets:	
Property, plant and equipment	579,906
Intangible assets	615
Trade and other receivables[1]	309,248
Cash and cash equivalents	3,104
	892,873
Liabilities	
Trade and other payables	(211,194)
Deferred tax liabilities	(78,012)
	(289,206)
Total identifiable net assets at fair value	**603,667**
Goodwill arising on acquisition	75,800
Fair value of non-controlling interest on acquisition	(204,800)
Fair value of purchase consideration transferred	**474,667**

Acquisition - date fair value of consideration transferred	
Cash paid for the acquisition of 50% preference shares	10,000
Cash paid at acquisition as advance for shares issuance	25,850
Cash paid after acquisition date for shares issuance	240,817
Cash payable at reporting date	8,000
Derivative asset	190,000
Consideration transferred	**474,667**

The cash outflow on acquisition is as follow:	
Net cash acquired with the subsidiary	3,104
Cash paid	(35,850)
Net consolidated cash outflow	**(32,746)**

[1] Included in Trade and other receivables is an amount of $248.8 million receivable from Energean E&P Holdings due for share capital increases, of which $240.8 million was paid in April 2018.

The balances above which were increased as a result of fair value adjustments being applied upon acquisition are oil & gas properties and deferred tax liabilities.

Goodwill of $75.8 million has been recognised upon acquisition. An amount of $79.0 million was due to the requirement of IAS 12 to recognise deferred tax assets and liabilities for the difference between the assigned fair values and tax bases of assets acquired and liabilities assumed. The assessment of fair value of such licences is therefore based on cash flows after tax. Nevertheless, in accordance with IAS 12 Sections 15 and 19, a provision is made for deferred tax corresponding to the tax rate of Israel (23%) multiplied by the difference between the acquisition cost and the tax base. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a direct result of the recognition of this deferred tax adjustment ("technical goodwill"). None of the goodwill recognised will be deductible for income tax purposes.

5. Revenue

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
Crude oil sales	24,090	24,782
Sales of scrap	-	8
Rendering of services	1,421	1,524
Petroleum products sales	746	440
Total revenue	**26,257**	**26,754**

6. Operating profit/(loss) before taxation

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
(a)		
Cost of oil sales		
Operating costs	13,234	12,031
Depreciation and amortisation	12,987	8,034
Movement in inventories of oil	(9,669)	2,908
Total cost of oil sales	16,552	22,973
Cost of services	1,223	1,281
Total Cost of sales	17,775	24,254
(b)		
Administration expenses		
Payroll costs	1,318	1,485
Depreciation and amortisation	206	143
Other General & administration expenses	3,311	854
	4,835	2,482
(c)		
Selling and distribution expense		
Payroll costs	80	96

Other Selling and distribution expense	138	74
	218	170

(d)

Exploration and evaluation expenses

Staff costs	292	130
Third party fees	317	109
	609	239

(e)

Other operating (income)/expenses

Other income	(55)	-
Gain from disposal of subsidiary	-	(1,461)
Other expenses	89	17
Provision for litigation expenses (note 22)	(7,427)	8,572
Provision for bad debts	-	402
	(7,393)	7,530

7. Finance cost

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
Other finance costs and bank charges	295	490
Interest expense on long terms borrowings	7,395	18,748
Unwinding of discount	204	123
	7,894	19,361
Less: Interest capitalised (Note 12)	(1,386)	(647)
Total finance cost	**6,508**	**18,714**

The decrease versus the previous period (1H 2017: $18.7 million) is associated with conversion of a shareholders' loan to preference shares at the end of 1H 2017 (refer to note 19).

8. Gain on derivative / fair value measurements

The information set out below provides information about how the Group determines the fair values of various financial assets and liabilities.

The fair values of the Group's financial assets and liabilities measured at amortised cost approximate to their carrying amounts at the reporting date. The carrying value less any estimated credit adjustments for financial assets and financial liabilities with a

maturity of less than one year are assumed to approximate their fair values due to their short term-nature.
The Group had one material financial asset are measured at fair value at 31 December 2017 which relates to the Energean Israel B shares.
On 30 June 2017 the Group entered into a Reorganisation Agreement which was subsequently amended by the "Supplementary Agreement" dated 31 October 2017, for full description of this transaction please refer to notes 31.4 and 34.2 of the Company's Annual Report for the year 2017 .
The valuation technique used multiplied the estimated likelihood of an Exit (being an IPO or a Sale) by the estimated difference between the consideration payable under the commitment and the estimated value of the B shares acquired under the commitment. The key input assumptions used in the fair value measurement calculation were the estimated likelihood of an IPO event and value of the B shares. An Exit in the form of a Sale was considered to be of negligible likelihood. The other significant inputs are the transaction prices applicable in an Exit Event, which are contractually agreed amounts, and the discount rate assumption used in the calculation, which was 11.5%. The fair value of the derivative asset was a Level 3 fair value measurement in the fair value measurement hierarchy, because the valuation relied significantly on input assumptions that were unobservable.
On remeasurement on 31 December 2017, the value of the B shares was estimated based on the price negotiated at a similar time with a third party for another tranche of the B shares in a separate transaction. The likelihood of a future IPO occurring was estimated as of 31 December 2017 to be 50% having regard to the considerable progress made to prepare for an IPO as of that date, but also to the fact that there were a number of significant steps not wholly under the control of the Group that remained to be achieved, and the inherent uncertainty in achieving any IPO due to capital market conditions.
Also on 31 October 2017, under the Supplementary Agreement the consideration payable to acquire the B shares in the event of an IPO was reduced from $150 million to $10 million. The resulting increase in the value of the derivative asset of $67.5 million (after applying the 50% IPO likelihood assumption and other discounting effects) is recorded in the consolidated statement of changes in equity as the Supplementary Agreement is a transaction with owners, giving the derivative asset a closing value as of 31 October 2017 of $91.6 million. As of 31 December 2017 the derivative asset was further increased to $93.3 million due to unwinding of the discount applied at the recognition, resulted in additional gain of $1.7 million recorded in profit or loss.
On 16 March 2018 following the acquisition of a 50% economic interest in Energean Israel, as described in note 4 the Group derecognised the derivative asset at total fair value of $190 million.
At the time of the Company's admission to the Premium Segment of the London Stock Exchange on 21 March 2018, the probability of an IPO increased to 100%, increasing the fair value of the derivative to $190 million. The change in fair value of $96.7 million between 31 December 2017 and 30 June 2018 is included in "Gain on derivative" in the consolidated income statement as it is due to changes in measurement assumptions.

Upon recognition, this derivative was the only instrument in the Level 3 category of the fair value hierarchy. There were no transfers in or out of this category in the period, and the only movement in the category relates to the increase in fair value of the derivative.
The fair value hierarchy of financial assets and financial liabilities that are not measured at fair value (but fair value disclosure is required) is as follows:

Fair value hierarchy as at 30 June 2018 (Unaudited)

	Level 1 $'000	Level 2 $'000	Level 3 $'000	Total $'000
Financial assets				
Trade and other receivables (note 17)	-	8,336	-	8,336
Cash and cash equivalents and bank deposits (note 15)	288,260	-	-	288,260
Total	**288,260**	**8,336**	**-**	**296,596**
Financial liabilities				
Financial liabilities held at amortised cost:				
Borrowings (note 20)	-	121,783	-	121,783
Trade and other payables (note 23)	-	210,807	-	210,807
Total	**-**	**332,591**	**-**	**332,591**

Fair value hierarchy as at 31 December 2017

	Level 1 $'000	Level 2 $'000	Level 3 $'000	Total $'000
Financial assets				
Trade and other receivables (note 17)	-	9,497	-	9,497
Cash and cash equivalents and bank deposits (note 15)	15,692	-	-	15,692
Total	**15,692**	**9,497**	**-**	**25,189**

Financial liabilities

Financial liabilities held at amortised cost:

Borrowings (note 20)	-	91,331	-	91,331
Trade and other payables (note 23)	-	63,442	-	63,442
Total	**-**	**154,773**	**-**	**154,773**

9. Taxation

(a) Taxation charge

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
Corporation tax - current year	(500)	(137)
Corporation tax - prior years	(129)	(2,208)
Deferred tax (Note 14)	5,951	(6,754)
Total taxation income / (expense	**5,322**	**(9,099)**

(b) Reconciliation of the total tax charge

The Group calculates its income tax expense based on IAS 34 by applying the estimated weighted-average annual effective income tax rate to pre-tax income for the interim period.

The tax (credit)/charge recognised in the income statement is reconciled to the Group's weighted average tax rate of 6.48% (30 June 2017: 54.5%). The differences are reconciled below:

	6 months ended 30 June (Unaudited)	
	2018	**2017**
	$'000	**$'000**
Corporation tax - current year	(500)	(137)
Corporation tax - prior years	(129)	(2,209)
Deferred tax (Note 14)	5,951	(6,753)
Total taxation income/(expense)	5,322	(9,099)
Profit/(loss) before tax	**82,078**	**(5,826)**
Tax calculated at the applicable tax rates	(20,520)	1,457
Impact of different tax rates	(83)	11
Reassessment of recognized deferred tax asset in the current period	2,425	(160)
Permanent differences	23,629	(8,188)
Other adjustments	-	(11)

Prior year tax	(129)	(2,208)
Taxation income/(expense)	**5,322**	**(9,099)**

10. Discontinued operations

At 31 December 2016, Energean Israel Limited was presented as a wholly owned subsidiary of Energean E&P Holdings Limited. Based on the Kerogen convertible loan and founding shareholder loans, the Group lost control of Energean Israel Limited on 13 June 2017 and was therefore presented as a discontinued operation in accordance with IFRS 5*Non-Current Assets Held for Sale and Discontinued Operations*.

The results of the discontinued operations, which have been included in the consolidated statement of profit or loss for the period ended 30 June 2017, were as follows:

	6 months ended 30 June 2017 $'000
Administration expenses	(1,112)
Exploration and evaluation expenses	-
Operating loss	**(1,112)**
Finance costs	(304)
Finance income	11
Income from foreign exchange transactions	2
Share of results of joint venture	-
Profit / (loss) from discontinued operations	**(1,403)**

A $1.5 million gain on disposal of the subsidiary was recognised in other income in profit or loss, based on the difference between the consideration received (nil) and the net liability position of Energean Israel Limited as of 13 June 2017 of $1.5 million.

Details of the cash flows of the discontinued operations which are included in the consolidated statement of cash flows of the period ended 30 June 2017 are as follows:

	6 months ended 30 June 2017 $'000
Operating activities	(985)
Investing activities	(2,715)
Financing activities	4,702
Net cash from discontinued operation	**1,002**

11. Earnings per share

The earnings per share has been calculated by dividing the net profit or loss for the period by the weighted average number of shares outstanding during the period ended 30 June 2018 and 30 June 2017. There were no potentially dilutive instruments outstanding during any period, therefore the basic and diluted earnings per common share were equal.

	6 months ended 30 June (Unaudited)	
	2018	**2017**
Income / (Loss) from continuing operations attributable to owners of the Company ($'000)	90,069	(13,523)
Net Results from discontinued operations ($'000)	-	(1,403)
Weighted average number of ordinary shares in issue during the year	111,733,179	70,643,120

Fully diluted average number of ordinary shares during the year	111,733,179	70,643,120
Total income / (loss) from continuing operation per share	**$0.81/share**	**($0.19)/share**
Total income / (loss) from discontinued operations per share	**$0.81/share**	**($0.02)/share**

12. Tangible assets

Tangible Assets at Cost	**Oil and gas properties $'000**	**Other property, plant and equipment $'000**	**Total $'000**
At 1 January 2017	**296,662**	**74,773**	**371,435**
Additions	61,113	4,629	65,742
Capitalised depreciation	2,388	-	2,388
Change in environmental rehabilitation provision	2,876	-	2,876
Foreign exchange impact	33,077	8,939	42,016
31 December 2017	**396,116**	**88,341**	**484,457**
At 1 January 2018	**396,116**	**88,341**	**484,457**
Additions	96,374	9,246	105,620
Acquisition of subsidiary (Note 4)	579,826	80	579,906
Capitalised depreciation	1,232	-	1,232
Change in environmental rehabilitation provision	726	-	726
Foreign exchange impact	(3,629)	(3,702)	(7,331)
At 30 June 2018	**1,070,645**	**93,965**	**1,164,610**
Accumulated Depreciation			
At 1 January 2017	**117,248**	**24,007**	**141,255**
Charge for the period			
-Expensed	17,021	788	17,809
-Capitalised to oil and gas properties	-	2,388	2,388
Impairment	-	1,344	1,344
Foreign exchange impact	12,952	(1,267)	11,685
At 31 December 2017	**147,221**	**27,260**	**174,481**
At 1 January 2018	**147,221**	**27,260**	**174,481**
Charge for the period	-		

-Expensed	12,587	539	13,126
-Capitalised to oil and gas properties	-	1,279	1,279
Foreign exchange impact	2,799	(2,117)	682
At 30 June 2018	**162,607**	**26,961**	**189,568**
Net carrying amount			
At 31 December 2017	**248,895**	**61,081**	**309,976**
At 30 June 2018	**908,038**	**67,004**	**975,042**

Borrowing costs capitalised for qualifying assets, included in "additions" of oil & gas properties, for the six months ended 30 June 2018 amounted to $1.4 million (year ended 31 December 2017: $1.3 million). The interest rates used:

- 9.09% (for the six months ended 30 June 2018)
- 7.03% (for the year ended 31 December 2017)

During the year ended 31 December 2014 and in view of its future drilling campaigns, the Group acquired and initiated the upgrade work of a Drilling Rig (Energean Force). The Group has issued a first preferred mortgage on the aforementioned Energean Force, in favour of the European Bank for Reconstruction and Development (EBRD).
The depreciation charge of the Energean Force has been capitalised in the oil and gas properties.
The impairment charges in 2017 relates to impairment of drilling materials in West Kom Ombo license and are recorded under "exploration and evaluation expenses" in the profit or loss.

13. Intangible assets

	Exploration and evaluation assets $'000	Other intangible assets $'000	Total $'000
Intangibles at Cost			
At 1 January 2017	**7,963**	**1,299**	**9,262**
Additions	2,871	281	3,152
Write off of exploration and evaluation costs	(6,663)	-	(6,663)
Disposal of Exploration and evaluation cost	(1,000)	-	(1,000)
Exchange differences	440	82	522
31 December, 2017	**3,611**	**1,662**	**5,273**
Additions	1,590	10	1,600
Acquisition of subsidiary (Note 4)	615	-	615
Exchange differences	(343)	(25)	(368)
At 30 June 2018	**5,473**	**1,647**	**7,120**
Accumulated Amortisation			
At 1 January 2017	**240**	**744**	**984**
Charge for the period	-	200	200
Exchange differences	21	68	89
31 December, 2017	**261**	**1,012**	**1,273**
Charge for the period	-	103	103
Exchange differences	(261)	(19)	(280)
30 June, 2018	**-**	**1,096**	**1,096**

Net Carrying Amount			
At 31 December 2017	**3,350**	**650**	**4,000**
At 30 June 2018	**5,473**	**551**	**6,024**

Disposal of Exploration and evaluation cost

In March 2017, the Group agreed to farm out a 60% working interest and operatorship of the Ioannina licence to Repsol. The Group retains a 40% working interest as of 30 June December 2018. According to Farm out agreement:

- On the completion date, 31 March 2017, Repsol paid to the Group the consideration of $1.0 million for all past costs regarding the licence.
- Repsol will conduct the exploration of the Ioannina block, providing 90% of the committed investment up to $25 million and 60% thereafter in exchange for a 60% interest.

The disposal of exploration and evaluation cost included in the year ended 31 December 2017, relates to 60% of past expenditure in Ioannina lease area.

Write-off and impairments

The Group recognised $6.7 million in exploration and evaluation expenses in the period ended 31 December 2017, relating to exploration expenditure for West Kom Ombo in Egypt. West Kom Ombo is an exploration block in Upper Egypt, the licence for which expired on 2 October 2017. There are no recoverable costs associated with West Kom Ombo and the asset has been fully written off in 2017.

14. Net deferred tax (liability)/ asset

Deferred tax (liabilities)/assets	**Property, plant and equipment $'000**	**Prepaid expenses and other receivables $'000**	**Inventory $'000**	**Tax losses $'000**	**Staff leaving indemnities $'000**	**Accrued expenses and other short-term liabilities $'000**	**Total $'000**
At 1 January 2017	**(51,100)**	**10,227**	**649**	**56,296**	**782**	**835**	**17,689**
Increase / (decrease) for the period through:							
profit or loss (Note 9)	(11,191)	(14,404)	(339)	15,565	(44)	711	(9,702)
other comprehensive income	-	-	-	-	74	-	74
Exchange difference	(7,726)	522	85	8,710	111	141	1,842
31 December 2017	**(70,017)**	**(3,656)**	**395**	**80,571**	**923**	**1,687**	**9,903**
Retrospective application of IFRS 9 (note 2.1)	-	-	-	-	-	(4,337)	(4,337)
At 1 January 2018 (restated)	**(70,017)**	**(3,656)**	**395**	**80,571**	**923**	**(2,650)**	**5,566**
Acquisition of subsidiary (Note 4)	(79,117)	-	-	1,099	-	6	(78,012)
Increase / (decrease) for the period through:							
profit or loss (Note 9)	(3,613)	3,189	1,346	4,921	8	100	5,951
other comprehensive income	-	-	-	-	-	941	941
Exchange difference	1,251	3,061	(61)	(2,478)	(15)	(2,191)	(433)
30 June 2018	**(151,496)**	**2,594**	**1,680**	**84,113**	**916**	**(3,794)**	**(65,987)**

The change in the deferred tax liability is not equal to the origination of temporary difference as in Note 9 mainly because of the acquisition of the subsidiary company Energean Israel (business combination), as described in Note 4.

At 30 June 2018 the Group has unused tax losses of $338.3 million (as of 31 December 2017: $322.1 million) available to offset against future profits. A deferred tax asset has been recognised as of 30 June 2018 in respect of $84.1 million (as of 31 December 2017: $80.6 million of such tax losses. The Deferred Tax Asset of the Group due to tax losses carried forward does not expire as tax losses can be carried forward indefinitely.

Greece

Tax losses can be utilised to offset taxable profits for a period of time that is dictated by the tax legislation of each country. The

above carried forward unused tax losses arise almost exclusively from the Prinos Area. Tax losses incurred under the Prinos licence (Law2779/1999) can be utilised to offset taxable profits until the termination of Prinos exploitation area.
According to the Ioannina and Katakolo lease agreements the losses incurred in respect of a particular exploitation area prior to the commencement of any exploitable production shall be carried forward without any restrictions for such period. From the commencement of any exploitable production and thereafter, the general income tax provisions shall apply in relation to the carrying forward of losses (currently 5 years).
The Group expects that there will be sufficient taxable profit in the following years and that deferred tax assets, recognised in the consolidated financial statements of the Group, will be recovered.

Israel
The Group is subject to corporation tax on its taxable profits in Israel at the rate of 23%. The Capital Gain Tax rates depends on the purchase date and the nature of asset. The general capital tax rate for a corporation is the standard corporate tax rate.
Tax losses can be utilised for an unlimited period, and tax losses may not be carried back.
Tax losses occurring during the development or construction phases areto be deducted at the depreciation rate of the asset under development in respect of which they were created.
According to Income Tax (Deductions from Income of Oil Rights Holders) Regulations, 5716-1956, the exploration and evaluation expenses of oil and gas assets are deductible in the year in which they are incurred.
The Group expects that there will be sufficient taxable profit in the following years and that deferred tax assets, recognised in the consolidated financial statements of the Group, will be recovered.

15. Cash and cash equivalents

	6 months ended 30 June (Unaudited) 2018 $'000	Year ended 31 December 2017 $'000
Cash in hand	54,022	16
Bank demand deposits	213,456	8,128
Restricted bank deposits	20,782	7,548
	288,260	**15,692**
Less: Non-current deposits	(3,838)	(1,899)
Current portion	**284,422**	**13,793**

Bank demand deposits comprise deposits and other short-term money market deposit accounts that are readily convertible into known amounts of cash. The effective interest rate on shortIterm bank deposits was 0.9% for the six months ended 30 June 2018 (year ended 31 December 2017: 0.34%).
Restricted bank deposits comprise mainly cash retained as a bank security pledge for the Group's performance guarantees in its exploration blocks of Israel, Montenegro, Ioannina and Aitolokarnania.
The fair value of cash and cash equivalents is $284.4 million (31 December 2017: $13.8 million).

16. Inventories

	6 months ended 30 June (Unaudited) 2018 $'000	Year ended 31 December 2017 $'000
Raw materials and supplies	4,922	4,956
Crude oil	13,758	4,573
Total inventories	**18,680**	**9,529**

17. Trade and other receivables

	6 months ended 30 June (Unaudited) 2018 $'000	Year ended 31 December 2017 $'000
Trade and other receivables-Current		
Financial items:		
Trade receivables	336	9,313
Receivables from related parties (note 25)	8,000	184
	8,336	9,497
Non-financial items:		
Deposits and prepayments	12,971	9,090
Deferred borrowing fees, non-current	17,809	-
Deferred insurance expenses	7,233	-
Government subsidies	3,307	3,482
Advance payment to tax authorities against Mandatory Administrative Appeal (Note 22)	3,732	-
Refundable VAT	2,102	2,195
Reimbursement from insurance contracts	408	420
	47,562	15,187
	55,898	**24,684**
Trade and other receivables-Non Current		
Non-financial items:		
Deferred borrowing fees, current	38,133	-
Deferred Insurance expenses	8,218	-
Other deferred expenses	730	591
	47,081	**591**

[1] This item represents expenses bank fees and third parties' fees that the Group has incurred in connection with Karish-Tanin debt raising, which completed on March 2, 2018.
Finance costs of debt are allocated to periods over the term of the related debt at a constant rate on the carrying amount. Arrangement fees and issue costs are deducted from the debt proceeds on initial recognition of the liability and are amortised and charged to the income statement as finance costs over the term of the debt.
The funds from the debt are expected to be received starting 2019. Therefore, the Group will amortise the deferred loan fees in accordance with the rate of withdrawal of funds from the Karish development loan, from January 2019 to the final maturity date of said loan.

18. Share capital

The Company's initial share capital amounted to £50 thousand ($65k), consisting of an issuance of 50,000 ordinary shares of a nominal value of £1.00 ($1.3) each on 8 May 2017. On 30 June 2017 the Company effected a 100 for 1 share split resulting in 5,000,000 ordinary shares of a nominal value of £0.01 ($0.013) each.
On 30 June 2017, the Company also became the parent company of the Group through the acquisition of the full share capital of

Energean E&P Holdings Limited, in exchange for 65,643,120 £0.01 ($0.013) shares in the Company issued to the previous shareholders. As of this date, the Company's share capital increased from £50 thousand ($65k) to £706 thousand ($917k). From that point, in the consolidated financial statements, the share capital became that of Energean Oil & Gas plc. The previously recognised share capital of $14,904 thousand and share premium of $125,851 thousand was eliminated with a corresponding positive merger reserve recognised of $139,903 thousand. The below tables outline the share capital of the Company.
On 21 March 2018, the Company issued 72,592,016 new shares in relation to the placement of its initial public offering of ordinary shares at £4.55 per share comprising an offer of 72,592,016 new shares.

	6 months ended 30 June (Unaudited)		Year ended 31 December	
	2018		2017	
	Number of shares	$'000	Number of shares	$'000
Authorised				
Ordinary shares of £0.01 each	**152,823,238**	**2,062**	**70,643,120**	**917**
Issued and fully paid				
On 1 January	70,643,120	917	-	14,904
Group restructuring	-	-	65,643,120	(14,052)
Issuance of shares and share split	82,180,118	1,145	5,000,000	65
At 30 June / 31 December	**152,823,238**	**2,062**	**70,643,120**	**917**

19. Non-controlling interests

	Voting rights		Share of loss		Accumulated balance	
	6 months ended 30 June (Unaudited)	Year ended 31 December	6 months ended 30 June (Unaudited)	Year ended 31 December	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017	2018	2017	2018	2017
	%	%	$'000	$'000	$'000	$'000
Kavala Oil S.A.	0.08	0.08	(5)	(9)	289	294
Energean International Limited	-	-	-	-	-	224,000
Energean Israel Ltd	30.00	30.00	(2,664)	(9)	225,136	-

Energean International Limited

On 30 June 2017, as part of the Reorganisation Agreement, the loan from Third Point in Energean International Limited was discharged in consideration for the issuance of 224,000 new preference shares in Energean International Limited. The Group derecognised the $230.8 million carrying value of the loan and recognised $224.0 million in equity for the preference shares. The difference of $6.8 million was recognised in other reserves as a capital contribution, as Third Point is an ultimate shareholder of the Group. The $224.0 million equity recognised for the preference shares represented a non-controlling interest in a subsidiary of the Group.
On Company's admission to the London Stock Exchange and pursuant to the terms of the reorganisation, the Energean International preference shares held by Third Point were converted to 9,270,038 common shares in the Company. This conversion solely impacts equity and non-controlling interests and had no impact on the Company's net assets.

Energean Israel Limited

On 29 March 2018, the Group, following a final investment decision in respect of the Karish and Tanin assets, after acquiring the 50% founders shares (refer to note 8), subscribed for additional shares in Energean Israel for an aggregate consideration of $266.7 million, payable in cash. Upon completion of this subscription, the Group holds 70% of the shares in Energean Israel, with Kerogen Capital holding the remaining 30%. The fair value of the non-controlling interest at the date of the acquisition of the additional 20% and control of the company, amounted to $204.8 million (refer to note 4).

20. Borrowings

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	

		2017
	$'000	$'000
Net Debt		
Current borrowings		12,500
Non-current borrowings	121,783	78,831
Total borrowings	121,783	91,331
Less: Cash and cash equivalents and bank deposits	(288,260)	(15,692)
Net Debt (1)	**(166,477)**	**75,638**
Total equity (2)	1,037,786	288,982
Gearing Ratio (1/2):	**(16,04%)**	**26.17%**

On 30 January 2018, the Group's existing EBRD Senior Facility Agreement was amended and restated pursuant to the RBL Senior Facility Agreement. The RBL Senior Facility Agreement comprises two facilities-a facility of up to $105.0 million with EBRD and the Black Sea Trade and Development Bank as lenders and a $75.0 million facility pursuant to which the Export-Import Bank of Romania Eximbank SA and Banca Comerciala Intesa Sanpaolo Romania S.A. (with 95% insurance cover from the Romanian ECA) as lenders. Proceeds from the Romanian Club Facility will finance exclusively 85% of the value attributable to goods and services under the GSP Engineering, Procurement, Construction and Installation Contract (EPCIC) contract. The facility is secured by substantially all of the assets of the subsidiary company Energean Oil & Gas S.A. and a guarantee from Energean E&P Holdings and a pledge of its shares in Energean Oil & Gas S.A. The facility will have a seven-year tenor.

21. Retirement benefit liability

The Group provides retirement benefits in the form of lump sum amounts based on an unfunded fixed benefit retirement plan to its employees.

According to the plan, a certain percentage of the current salary is converted into a pension component each year until retirement. Pensions under this scheme are paid out when a beneficiary has reached the age of 65. Eligible employees are required to contribute 2% of this pensionable salary.

These plans are not funded and are defined benefit plans in accordance with IAS 19. The Greek subsidiaries charge the accrued benefits in each period with a corresponding increase in the relative actuarial liability. The payments made to retirees in every period are charged against this liability. The liabilities of the Group arising from the obligation to pay termination indemnities are determined through actuarial studies, conducted by independent actuaries.

21.1 Provision for retirement benefits

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017
	$'000	$'000
Defined benefit obligation	3,219	3,288
Provision for retirement benefits recognised	**3,219**	**3,288**
Allocated as:		
Non current portion	3,219	3,288
	3,219	3,288

21.2 Defined benefit obligation

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017
	$'000	$'000
At 1 January	3,288	2,425
Current service cost	114	296

Interest cost	23	43
Extra payments or expenses	-	34
Actuarial losses - from changes in financial assumptions	-	258
Benefits paid	(111)	(86)
Exchange differences	(95)	318
At 30 June / 31 December	**3,219**	**3,288**

21.3 Actuarial assumptions and risks

The most recent actuarial valuation was made as of 31 December 2017 and it was based on the following key assumptions:

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017
	$'000	$'000
Discount rate	1.50%	1.50%
Expected rate of salary increases	3.59%	3.59%
Average life expectancy over retirement age	24,57 years	24,57 years
Inflation rate	1.75%	1.75%

22. Provisions

	Provision for environment rehabilitation	Litigation and other claims	Total
	$'000	$'000	$'000
At 1 January 2017	**2,240**		**2,240**
New provisions and changes in estimates	2,897	12,462	15,359
Payments	-	(3,839)	(3,839)
Unwinding of discount	229	-	229
Currency translation adjustment	322	683	1,005
At 31 December 2017	**5,688**	**9,306**	**14,994**
Current provisions	**-**	**9,306**	**9,306**
Non-current provisions	**5,688**	**-**	**5,688**
At 1 January 2018	**5,688**	**9,306**	**14,994**
New provisions and changes in estimates	725	(3,214)	(2,489)
Payments	-	-	-
Unwinding of discount	181	-	181
Currency translation adjustment	(157)	32	(125)
At 30 June 2018	**6,437**	**6,124**	**12,561**
Current provisions	**-**	**6,124**	**6,124**
Non-current provisions	**6,437**	**-**	**6,437**

Litigation and Other Claims

As of 31 December 2017 the Group recorded provision of $6.9 million for transfer pricing and income tax penalties following tax litigation in Greece, for the tax audit of the years 2008-2011 which was appealed. Furthermore, the Company recognised a provision for its unaudited tax years 2012 - 2016 of $4.2 million. This takes into consideration the outcome of the tax audit of the

Company's transfer pricing policies finalised for fiscal years 2010- 2011, which were the subject of the appeal. This amount corresponds to corporate income tax amount of $2.3 million plus penalties and interest of $1.9 million.
Following the receipt in June 2018 of the final favourable decision from the appeal process, the provision for transfer pricing and income tax penalties has been reversed and recorded in "other income" (note 6e) in the consolidated income statement. During 2015, Energean had been required to make a mandatory prepayment of 50% of the total exposure, $3.7 million to the Greek tax authorities. Following the final decision, Energean will proceed in recovering this amount.

23. Trade and other payables

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017
	$'000	$'000
Trade and other payables-Current		
Financial items:		
Trade accounts payable	40,145	47,965
Accrued Expenses[1]	80,532	11,124
Other creditors	48	2,281
Long-term liabilities payable in post year[3]	15,341	-
Other finance costs accrued	7,363	2,071
	143,429	63,441
Non-financial items:		
Deferred revenue[2]	10,000	-
Social insurance and other taxes	2,438	3,087
	12,438	3,087
	155,867	**66,528**
Trade and other payables-Non Current		
Financial items:		
Payables owed for license acquisition[3]	67,379	-
Non-financial items:		
Social insurance	2,203	2,544
	69,582	**2,544**

[1] Included in accrued expenses are mainly Karish field related development accruals (FPSO and Sub Sea construction cost) total amount of $66.5 million.

[2] Deferred revenue includes advance payments for crude oil sales.

[3] In December 2016, Energean Israel acquired the Karish and Tanin offshore gas fields for $40.0 million closing payment with an obligation to pay contingent consideration of $108.5 million plus interest inflated at an annual rate of 4.6% in ten equal annual payments. The contingent consideration was triggered on the earlier of the date on which a final investment decision of Karish & Tanin has been made or the date on which the aggregate expenditures in connection with the Israeli oil and gas leases exceed $150.0 million. Therefore as of 31 December 2017, Energean Israel did not recognise a liability in respect of the deferred consideration as was not probable that the contingent consideration would become payable. In March 2018 Energean Israel made a Final Investment Decision ("FID") on the Karish and Tanin offshore Israel leases. Consequently the company proceeded with the payment of the first instalment and the recognition of a liability in respect of the remaining deferred consideration at a discount rate 9.34%.

24. Share based payments

Analysis of share-based payment charge

	6 months ended 30 June (Unaudited)	
	2018	2017

	$'000	$'000
Employee Share Award Plan	608	-
Total share-based payment charge	**608**	**-**
Capitalised to intangible and tangible assets	356	-
Expensed as administration expenses	245	-
Expensed to exploration and evaluation expenses	7	-
Total share-based payment charge	**608**	**-**

Employee Share Award Plan (ESAP)
Most Group employees are eligible to be granted nil exercise price options under the ESAP.

On 24 May 2018, the Company, following its admission on the London Stock Exchange on 21 March 2018 granted conditional awards to most of the Group employees under the Energean 2018 Long Term Incentive Plan (LTIP) over 659,050 ordinaryshares in Energean Oil & Gas plc.

Subject to the rules of the LTIP, half of the shares subject to each employee Award will vest on 22 November 2018, and the remainder will vest on 22 November 2019.

25. Related parties

25a. Related party relationships

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.
The Directors of Energean Oil & Gas Plc are considered to be the only key management personnel as defined by IAS 24. The following information is provided in relation to the related party transaction disclosures provided in note 25b below:
Adobelero Holdings Co Ltd is a beneficially owned holding company controlled by Panos Benos, the CFO of the Group.**Growthy Holdings Co Ltd** is a beneficially owned holding company controlled by Matthaios Rigas, the CEO of the Group.**Oil Co Investments Limited** is beneficially owned and controlled by Efstathios Topouzoglou, a Non-Executive Director of the Group. The nature of the Group's transactions with the above related parties is mainly financing activities.
Third Point Hellenic Recovery (Lux) S.A.R.lis a US based institutional investor that has historically supported the Group through debt funding and remains one of the Group's largest shareholders (refer to note 18).
Kerogen Capital is an independent private equity fund manager specialising in the international oil and gas sector, which currently holds the 30% of Energean Israel nominal shares.
Seven Maritime Company (Seven Marine)is a related party company controlled by one the Company's ultimate shareholder Mr Efstathios Topouzoglou. Seven Marine owns the offshore supply ships Valiant Energy and Energean Wave which supports the Group's investment program in northern Greece.
Energean Israel Limited was an associate to the Group until 29 March 2018, when the company became a subsidiary to the Group. A Technical Services Agreement dated 19 December 2016 was signed between Energean International Limited and Energean Israel Limited for the provision of project advisory, technical and commercial consulting services between the two companies.
Abbey Investing: Property lease to other related party includes rental fees of a flat in London. The property is beneficially owned by Energean's executive director spouse. The flat is used as a company flat for Energean's staff and consultants.

25b. Related party transactions

Purchases of goods and services

		6 months ended 30 June (Unaudited)	
		2018	2017
		$'000	$'000
	Nature of transactions		
Third Point Hellenic Recovery Fund L.P.	Finance cost	-	16,070
Growthy Holdings CO	Finance cost	-	43
Oilco Investments Limited	Finance cost	-	43
Adobelero Holdings CO	Finance cost	-	4
Other related party "Seven marine"	Vessel leasing	3,166	3,189
Other related party "Abbey Investing"	Property lease	17	32

		3,183	19,382

Revenue and other income

		6 months ended 30 June (Unaudited)	
		2018	2017
		$'000	$'000
	Nature of transactions		
Energean Israel Ltd	Technical services	226	-
		226	-

25c. Related party balances

Payables

		6 months ended 30 June (Unaudited)	Year ended 31 December
		2018	2017
		$'000	$'000
	Nature of balance		
Energean Israel Ltd	Technical services	-	1,477
Seven Marine	Vessel leasing	3,401	2,562
		3,401	4,039

Receivables

		6 months ended 30 June (Unaudited)	Year ended 31 December
		2018	2017
		$'000	$'000
	Nature of balance		
Kerogen Capital	Amounts due for share capital increase in Energean Israel	8,000	-
		8,000	-

26. Capital commitments

In acquiring its oil and gas interests, the Group has pledged that various work programmes will be undertaken on each permit/interest. The exploration commitments in the following table are an estimate of the net cost to the Group of performing these work programmes:

	6 months ended 30 June (Unaudited)	Year ended 31 December
	2018	2017
	$'000	$'000
Due within one year	10,964	7,505

Due later than one year but within two years	22,747	14,458
Due later two years but within five years	-	500
	33,711	**22,463**

27. Legal cases and contingent liabilities

The Group had no material contingent liabilities as of 30 June 2018 and 31 December 2017.

28. Subsequent events

On 16 August the Company received an updated independent Competent Persons Report from Netherland Sewell & Associates ("NSAI") for its Israeli portfolio. The updated CPR includes the certification of 63 bcm (2.2 Tcf) of 2P reserves and 7.5 Tcf of gross prospective resources and is the first assessment of prospective resources in the new Blocks (12, 21, 22, 23 and 31) that were awarded as part of the recent offshore licencing round.

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END

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RNS Number : 6041A
Energean Oil & Gas PLC
12 September 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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RNS Number : 6091B
Energean Oil & Gas PLC
21 September 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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PMELLFVEAEILFIT

RNS Number : 5951C
Energean Oil & Gas PLC
02 October 2018

For immediate release

Energean Oil and Gas

("Energean" or the "Company")

Appointment of Chief Operating Officer

Strengthening of Senior Management Team

02 October 2018 - Energean Oil & Gas PLC ("Energean" or "the Company"; ENOG:LN) is pleased to announce the appointment of Iman Hill as Chief Operating Officer effective 1 November 2018.

Iman is a Petroleum Engineer with over 30 years' global experience in the oil and gas industry with extensive expertise in the technical and commercial aspects of the petroleum business, in particular development and production projects.

Prior to joining Energean, Iman was the Technical Director, GM UAE and President Egypt for Dana Gas PJSC responsible for managing global operations. She began her career with BP in 1984 and worked in a variety of technical positions before becoming a Senior Reservoir Engineer. In 1997 she joined Shell International where she held positions such as Senior Regional Adviser Africa to the E&P CEO and the Chairman of Shell E&P Business Interface Manager, Middle East and GM Shell Egypt and Chairwoman of Shell Companies in Egypt. From 2005 to 2011 Iman worked at BG Group in roles such as Senior Vice President for Developments and Operations responsible formaturing developments to sanction, well engineering and operations.

Iman previously held Non-Executive Directorships at Outokumpu and EMGS.

Mathios Rigas, CEO Energean Oil & Gas, commented:

"Iman is a highly experienced oil and gas professional with a proven track record and we are delighted to welcome her to the team. She brings a wealth of operational and technical expertise and we look forward to working closely with Iman across all of our global operations as we continue to grow production, profitability and deliver shareholder value."

Enquiries

Energean **Tel: 07917 608 645**
Kate Sloan, Head of IR

Camarco (Financial PR) **Tel: 020 3757 4980**
Billy Clegg
Georgia Edmonds
Owen Roberts

About Energean Oil & Gas plc

Energean is a London Premium Listed independent E&P company with 13 licenses across offshore Israel, Greece and the Adriatic. Energean has 349 mmboe of 2P reserves and 48 mmboe of 2C resources across its portfolio.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO and produce first gas for the Israeli market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, and a 25 year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.

www.energean.com

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END

BOABUBDGUSGBGIB

RNS Number : 7144C
Energean Oil & Gas PLC
02 October 2018

Price Monitoring Extension

The auction call period has been extended in this security by 5 minutes.

Auction call extensions give London Stock Exchange electronic order book users a further opportunity to review the prices and sizes of orders entered in an individual security's auction call before the execution occurs. A price monitoring extension is activated when the matching process would have otherwise resulted in an execution price that is a pre-determined percentage above or below the price of the most recent automated execution today.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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RNS Number : 7153C
Energean Oil & Gas PLC
02 October 2018

Second Price Monitoring Extension

A second and final Price Monitoring Extension has been activated in this security. The auction call period is extended in this security for a further 5 minutes.

Following the first price monitoring extension this security would still have executed more than a pre-determined percentage above or below the price of the most recent automated execution today. London Stock Exchange electronic order book users have a final opportunity to review the prices and sizes of orders entered in this security prior to the auction execution.

The applicable percentage is set by reference to a security's Millennium Exchange sector. This is set out in the Sector Breakdown tab of the Parameters document at www.londonstockexchange.com/tradingservices

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APMBBBDGRGGBGID

RNS Number : 1916D
Energean Oil & Gas PLC
08 October 2018

For immediate release

Energean Oil and Gas

("Energean" or the "Company")

Analyst and Investor Site Visit

08 October 2018 - Energean Oil and Gas plc (LSE: ENOG) announces that it is holding a site visit for analysts and investors to the Company's operations in Israel and Greece.

In Israel, investors and analysts will meet with several of Energean's gas buyers and the Minister of Energy. The presentations will discuss growth in Israeli gas demand and Energean's key role in contributing to diversity and security of supply. TechnipFMC will make a presentation on the Karish and Tanin development, which Energean re-iterates as being on schedule to deliver first gas from the only FPSO in the Eastern Mediterranean in 1Q 2021.

Energean will be making a presentation about its assets in Greece on Wednesday 10 October, which will be made available on the Company's website in due course. 3Q 2018 production is confirmed as 4,080 bopd and full year guidance is re-iterated at 4,000 - 4,250 bopd.

No other material information will be disclosed.

Enquiries

Energean **Tel: 07917 608 645**
Kate Sloan, Head of IR

Camarco (Financial PR) **Tel: 020 3757 4980**
Billy Clegg
Georgia Edmonds
Owen Roberts

About Energean Oil & Gas plc

Energean is a London Premium Listed independent FTSE 250 E&P company with operations offshore Israel, Greece and the Adriatic. Energean has 349 mmboe of 2P reserves and 48 mmboe of 2C resources across its portfolio.

In August 2017 the Company received Israeli Governmental approval for the FDP for its flagship Karish-Tanin gas development project, where it intends to use an FPSO to produce first gas for the Israeli domestic market in 2021. In Greece, the Company is pursuing an ongoing investment and development programme to increase production from its Prinos and Prinos North oil fields and to develop the Epsilon oil field, located in the Gulf of Kavala, Northern Greece.

Energean has five exploration licences offshore Israel, a 25 year exploitation licence for the Katakolo offshore block in Western Greece and additional exploration potential in its other licences offshore Western Greece, and Montenegro.
www.energean.com

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MSCMABATMBIMBJP

RNS Number : 8010D
Energean Oil & Gas PLC
11 October 2018

TR-1: Standard form for notification of major holdings

NOTIFICATION OF MAJOR HOLDINGS (to be sent to the relevant issuer and to the FCA in Microsoft Word format if possible)[i]

1a. Identity of the issuer or the underlying issuer of existing shares to which voting rights are attached[ii]:	ENERGEAN OIL & GAS PLC	
2. Reason for the notification (please mark the appropriate box or boxes with an "X")		
An acquisition or disposal of voting rights		X
An acquisition or disposal of financial instruments		
An event changing the breakdown of voting rights		
Other (please specify)[iii]:		
3. Details of person subject to the notification obligation[iv]		
Name	Clal Insurance Company Ltd.	
4. Full name of shareholder(s) (if different from 3.)[v]		
Name	N/A	
City and country of registered office (if applicable)		
5. Date of the transaction and date on which the threshold is crossed or reached:	28 September 2018	
6. Date on which issuer notified (DD/MM/YYYY):	10 October 2018	
7. Threshold(s) that is/are crossed or reached: vi, vii	Below 11%	

8. Notified details							
A: Voting rights attached to shares							
Class/type of shares if possible using the ISIN CODE	**Situation previous to the triggering transaction**					**Resulting situation after the triggering transaction**	
	Number of shares	**Number of voting rights**	**Number of shares**	**Number of Voting Rights**		**% of voting rights**	
			Direct	**Direct**	**Indirect**	**Direct**	**Indirect**
Ordinary shares	**17,622,268**	**11.53%**	**855,044**	**855,044**	**15,608,034**	**0.56%**	**10.21%**

B: Financial Instruments according to Art. 13(1)(a) of Directive 2004/109/EC (DTR5.3.1.1 (a))				
Type of financial instrument	**Expiration date[x]**	**Exercise/ Conversion Period[xi]**	**Number of voting rights that may be acquired if the instrument is exercised/converted.**	**% of voting rights**
N/A				

C: Financial Instruments with similar economic effect to Qualifying Financial Instruments xv, xvi					
Type of financial instrument	**Exercise Price**	**Expiration date[x]**	**Exercise/ Conversion Period** xi	**Number of voting rights instrument refers to**	**% of voting rights**
N/A				Nominal	Data

Total (A+B+C)	
Number of voting rights	**Percentage of voting rights**
16,463,078	10.77%

9. Chain of controlled undertakings through which the voting rights and/or the financial instruments are effectively held, if applicable: xxi

Clal Insurance Company Ltd. ("Clal") controls directly or indirectly the voting rights attached to a total of 16,463,078 ordinary shares in Energean Oil & Gas Plc ("Energean") through several of its controlled undertakings, as stated below:

Of total of 16,463,078 ordinary shares (a) 855,044 Ordinary Shares are beneficially held for its own account; and (b) 15,608,034 Ordinary Shares are held for members of the public through, among others, provident funds and/or pension funds and/or insurance policies, which are managed by Clal and subsidiaries of Clal (Clal Pension and Provident funds Ltd. and Atudot Pension Fund for Workers & Independent Workers Ltd.) which operates under independent management and make independent voting and investment decisions.

The 16,463,078 ordinary shares represent 10.77% of the voting rights attached to Energean's shares (based on the total number of issued shares in Energean being 152,823,238 ordinary shares).

10. In case of proxy voting, please identify:	
Name of the proxy holder	N/A
The number and % of voting rights held	N/A
The date until which the voting rights will be held	N/A

11. Additional information[xvi]
N/A

Contact name:	Adi Barkan Stern Company Secretary Clal Insurance Enterprises Holdings Ltd
Contact Telephone:	+972-3-6387634

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Analyst Presentation

Energean: A New Story in the International Upstream Sector

8th May 2018

ENERGEAN
OIL & GAS

Today's Presenters



Mathios Rigas
Chief Executive Officer & Founding Shareholder

- Founding shareholder
- Petroleum Engineer with 21 years of investment banking and private equity experience mainly in the oil & gas sector
- c.12.7% shareholding post-IPO



Panos Benos
Chief Financial Officer

- Chartered accountant with more than 16 years oil & gas experience both in banking and industry
- Joined Energean from Standard Chartered Bank
- c.2.7% shareholding post-IPO

Senior Technical Team



Dr. Stephen Moore – ***Chief Growth Officer***

- 32 years of E&P experience at Shell, Maersk Oil and Mubadala
- Previously Senior Vice President – Technical at Mubadala



Fred Riddiford – ***Reservoir Engineering Manager***

- Reservoir Engineering with almost 40 years of experience
- Previously VP Reservoir Engineering at Mubadala



David Donaldson – ***Prinos Asset Manager and Managing Director, Kavala Oil***

- Petroleum Engineer with over 30 years of industry experience
- Held senior drilling engineer positions at Shell, Eni and Halliburton



Andreas Pelekanou – ***Karish Facilities Design Manager***

- 40 years of experience in the oil & gas sector
- Previously Technical Director at ThyssenKrup, Engineer Manager at Petroceltic, Hess and BHP Billiton



Yoram Laks – ***Israel Security Manager***

- 35 years of operational command service in the Israeli Navy where his positions included Commandant of the Naval academy, Ashdod Operational Arena Commander and Head of Naval Intelligence (N2)



Yaron Daissy – ***Karish Onshore Delivery Manager and Head Regulatory Compliance***

- Mechanical Engineer with over 20 years oil and gas experience
- Previously spent 15 years at Noble Energy Mediterranean Ltd where his roles included Deep Water GoM production manager and engineering manager for Tamar and Leviathan



Paul Rodgers – ***Karish Operations Manager***

- Over 23 years experience in the oil & gas sector
- Joined Energean from Petrofac, where his roles included Operations Manager and Regional Head (Americas)
- Previously spent 21 years with BP in various engineering roles



Photis Papadopoulos – ***Karish FPSO Delivery Manager***

- Mechanical engineer with over 25 years experience in the oil & gas sector
- Previous experience includes Project Engineer at Chevron, Technip and KBR



Steve Starkey Jones – ***Karish HSE Technical Safety Manager***

- 35 years experience within the industry, including senior engineering positions at PTTEP, Lundin and Tullow
- Provides HSE leadership for the design and implementation of Karish and Tanin



Vassilis Zenios – *Epsilon Project Manager*

- 25 years of oil & gas experience
- Experience in offshore heavy lift solutions and pipelines

Energean Board of Directors

Non-Executive Directors



Simon Heale – ***Independent Non-Executive Chairman***

- Currently serves as Chairman of Gulf Marine Services, Marex Spectron and Kaz Minerals
- Prior to this served as NED and Chairman of Panmure Gordon, and as NED of PZ Cussons, Morgan Advanced Materials, Coats and Carlton Commodities



Andrew Bartlett – ***Senior Independent Director***

- Started his career in Royal Dutch Shell where he worked for 21 years
- 11 years of investment banking experience and former Global Head of Oil & Gas M&A and Project Finance at Standard Chartered
- Advisor to Helios Investments and NED of Africa Oil and Impact Oil & Gas
- Served as Chairman of Azonto Energy and a NED of Eland Oil & Gas



Stathis Topouzoglou – ***Non-Executive Director***

- Shipowner with more than 35 years' experience in the energy transportation sector
- Founding partner of Energean Oil & Gas
- Principal shareholder and founder of Prime which has more than 35 vessels under management



David Bonanno – ***Non-Executive Director***

- Third Point representative to the Board
- Primary investment professional responsible for all Third Point's activities in Greece
- Previously worked at Cerberus and Rothschild



Ohad Marani – ***Independent Non-Executive Director***

- Board Member of Bank Leumi of Israel and member of the Investment Committee of Israel's Infrastructure Fund
- Previously Chairman of the board of Emmanuelle Energy, Israel Natural gas Lines and Alumot Investment House
- Served as Director-General of Israel Finance Ministry and also in the Israeli Embassy in Washington



Robert William Peck – ***Independent Non-Executive Director***

- Ambassador Peck has almost 35 years in the Government of Canada as a career Foreign Service Officer
- Resident mentor in the Human Resources Bureau at Global Affairs Canada
- Has held diplomatic roles in Nigeria, Switzerland, Algeria and Greece



Karen Simon – ***Independent Non-Executive Director***

- Currently Head of Director Advisory Services at JP Morgan with over 30 years of banking experience
- Previously Head of the Financial Sponsor Coverage Group and Global Co-Head of Asia and EMEA at JP Morgan
- On the board of Aker ASA and Youth Inc.

Executive Directors



Mathios Rigas
Chief Executive Officer



Panos Benos
Chief Financial Officer

Energean - A Leading E&P Player In The Eastern Mediterranean

4
Countries*

13
E&P licenses

17
Active wells

37
Years of experience as an offshore operator

393
Highly skilled employees**

51
MMbls oil 2P reserves

1,7
TCF gas 2C resources

45,9
MMbls oil 2C resources

12
Israeli GSPAs of total contracted volume up to 74 BCM

Israel values stated on a 70% working interest basis

*Offices in the UK, Israel, Greece, Cyprus, Egypt and Montenegro
** Excluding sub-contractors

IPO Summary

Main Market, Premium Listing

- Primary raise – **largest London IPO in 2018**

  Restoring confidence in the London O&G market after 4 years with strong institutional interest

- Only stock on the LSE offering exposure to the increasingly attractive East Mediterranean region

Major institutional interest

- Significant UK, Israeli and international participation
- Institutions have bought into the East Mediterranean opportunity

Flagship project: Developing Karish and Tanin, offshore Israel

Proceeds of primary raise will be used alongside the recently secured project financing to deliver production from Energean's Karish Development Project, offshore Israel, bringing competitively priced gas to the burgeoning Israeli energy market.

IPO completes another milestone on path to first gas

✓ Project financing in place

✓ EPCIC contract with TechnipFMC agreed

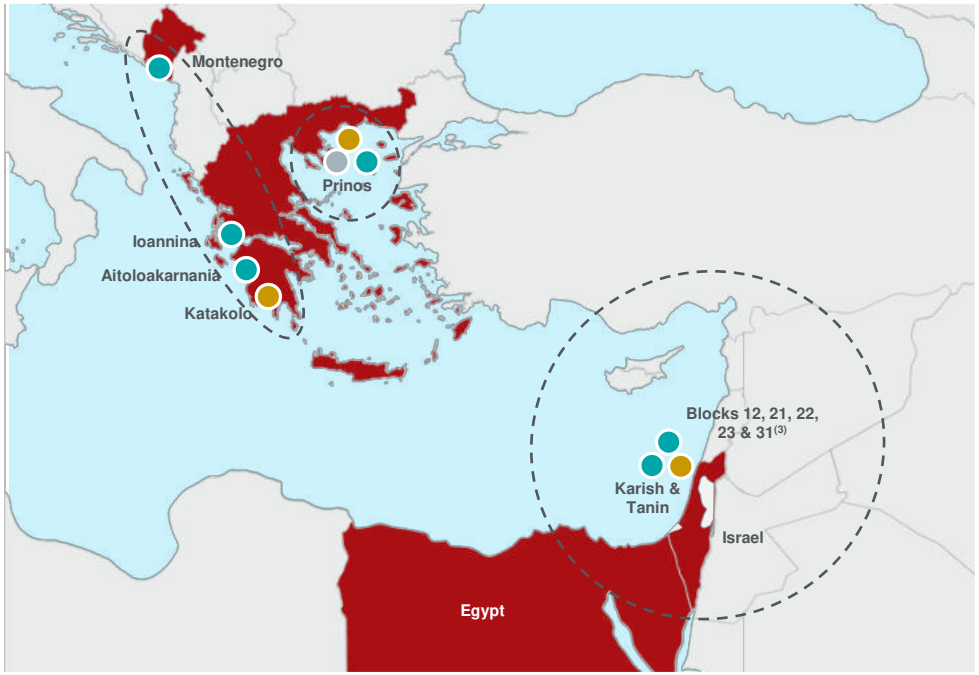
✓ Gas supply contracts for over 4 BCM per year underpinning our cashflow expectations

➔ Energean took FID for the Karish and Tanin Development in March 2018

Key information	
Offer price	£4.55 per Share
Market cap	Approx. £695 million ($968 million) at commencement of conditional dealings
Global Offer	Represents approx. 47.5% of the Shares of the Company
New Shares	72,592,016
Gross proceeds	Approx. £330 million ($460 million)
Ticker	ENOG



The Energean Investment Proposition



Low Cost Efficient Production Base

Production from low cost, assets in Greece

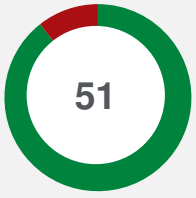
Material and De-Risked Development Project

Transformational development of $1.6 Billion project in Israel

Multiple Growth Opportunities in a Highly Prospective Region

Exploring the East Med with low commitment high impact assets in Greece, Montenegro and Israel

2P *(mmboe)*



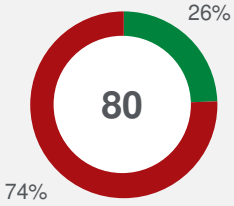
2C *(mmboe)*



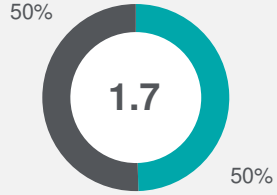
Product. 2017(1) *(kboepd)*



Product. 2021E(2) *(kboepd)*



Greece & Israel Value(2) *($bn)*



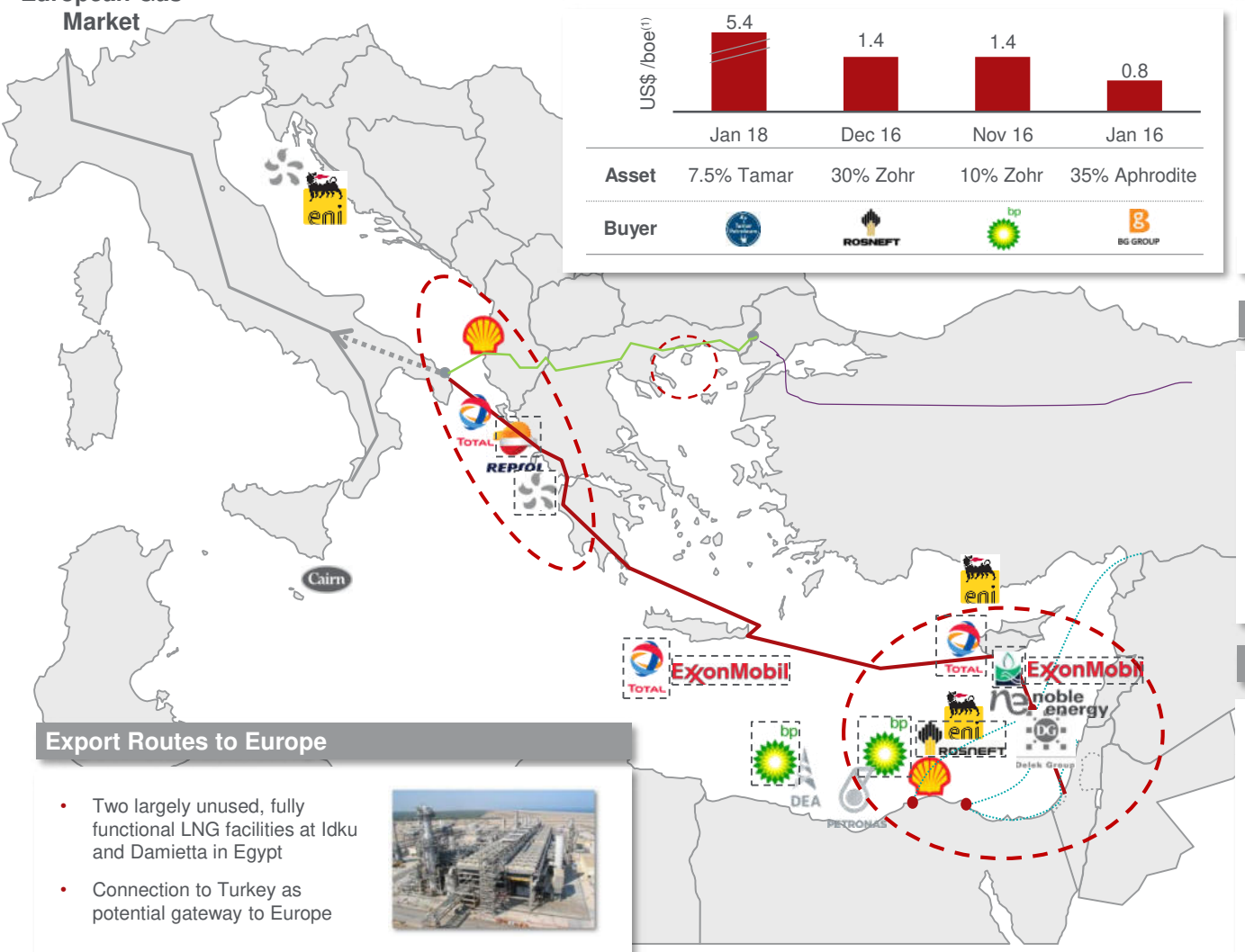
Oil Gas Greece Israel

Note: (1) Exit rate. (2) Based on K&T, Prinos and Katakolo NSAI CPRs CPR values. Value calculated as the present value of the asset net cashflows discounted at 10%, adjusted for Company Israel Corporate Tax. All Israel values stated on a 70% working interest basis

Source: NSAI CPRs.

Strategic Focus Around An Increasingly Active Region

European Gas Market

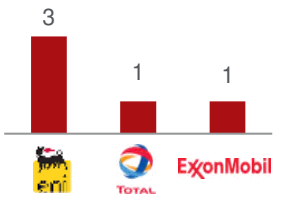


Increasing M&A Activity

Asset	7.5% Tamar	30% Zohr	10% Zohr	35% Aphrodite
Buyer		ROSNEFT	bp	BG GROUP

Cyprus

Future exploration wells in 2018



"Calypso 1 is a promising gas discovery and confirms the extension of the Zohr like play in the Cyprus EEZ […] that could contain more than 230 BCM of gas, and contains not less than 170 BCM"

Claudio Descalzi, ENI CEO

East Mediterranean Pipeline

- Gas pipeline connecting East Med via Greece and Italy with the European gas network
- MoU signed between Israel, Greece, Italy and Cyprus supporting the pipeline construction
- Classified as European Project of Common Interest with EU sponsoring 50% of pre-FEED costs
- Targeted project completion by 2025

Israel / Egypt Gas Deal

- Israeli firms signed a $15 bn deal to export gas to Egypt from Leviathan and Tamar
- Agreement to supply 64 bcm of gas over 10 years
- Implied price of c.$6.6/mmbtu

DOLPHINUS



Export Routes to Europe

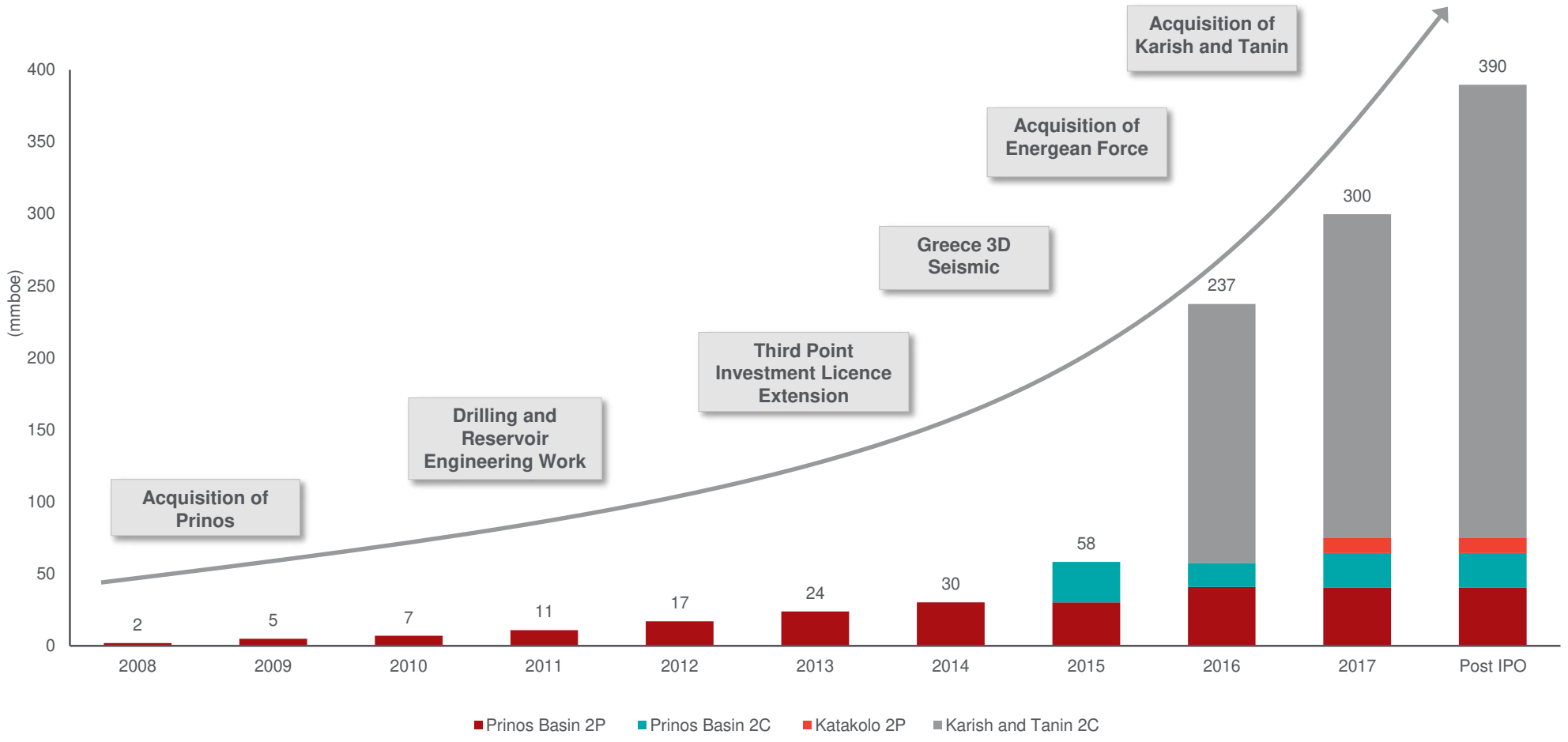
- Two largely unused, fully functional LNG facilities at Idku and Damietta in Egypt
- Connection to Turkey as potential gateway to Europe

Energean Focus Regions | Newcomers | Trans-Anatolian Pipeline | Trans-Adriatic Pipeline | East-Med Pipeline | Other Proposed Pipelines | Egypt LNG plant

Note: (1) Transaction value / boe.
Source: Company Filings, Herold.

Transformational Reserves And Resources Growth

Commercialisation of Reserves and Resources Through De-Risking(1)



Note : (1) 2016: 50% WI in Karish and Tanin, *Post IPO*: 70% WI in Karish and Tanin. Figures for 2008 - 2010, 2012 and 2013 based on company estimates.
Source: NSAI CPRs.

Prinos Production Provides Stability and Operating Capability

Stable Production Base Around Prinos Basin

- 40.5 mmboe of 2P reserves and 23.8 mmboe of 2C resources
- 2017 exit production of 4,086 bopd, with material production growth potential
- Operatorship position for all fields
- High netback supported by favourable fiscal terms
- Low risk 2C to 2P conversion
- Owned infrastructure offers operational flexibility
- Processing infrastructure located close to major planned oil & gas pipelines
- No abandonment liability for pre-existing infrastructure
- Long term offtake agreement signed with BP until November 2025 or delivery of 25 mmbbls of oil to BP

Energean Force – Energean Owned Drilling Rig



Existing Infrastructure In Place

Offshore Platform Complex



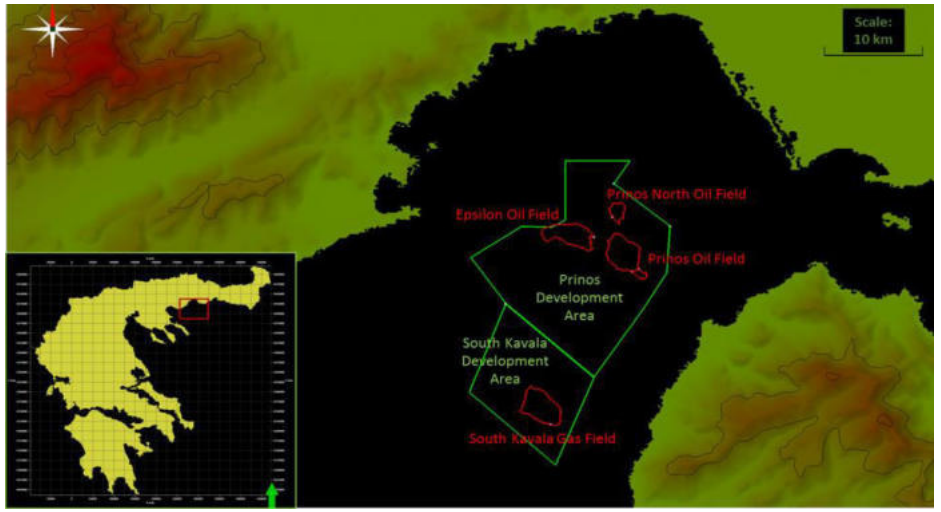
Sigma Processing Plant – 27,500 bopd Capacity



Source: Company.

Prinos Basin Development Plan

Development Area



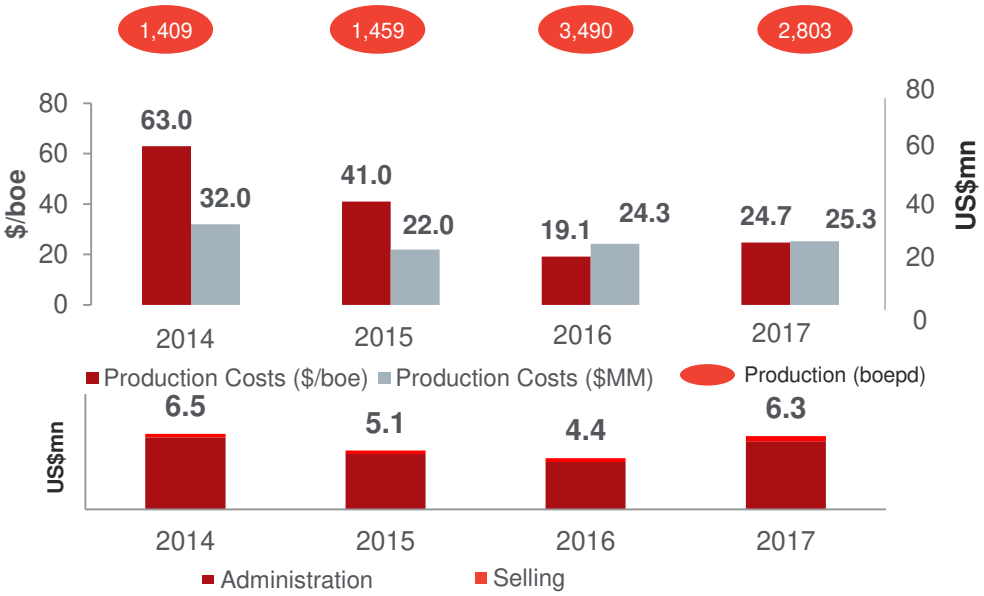
Key Financing Terms

- **Amount:** $180 mn (from $75 mn of the previous RBL facility)
- **Usage:** Refinance existing debt, Epsilon development, other Prinos fields and other corporate purposes
- **Tenor:** 7 years
- **Interest:** L+4.9% (L+3% for the Romanian facility)
- **Lenders:** European Bank; Black Sea Trade & Development Bank; EximBank Romania; Intesa Sanpaolo Bank Romania

Development Plan

- Prinos Basin development plan consists of drilling an additional 25 wells
  - 8 wells in 2018 & 2019
  - 22 wells with the Energean owned rig
  - 3 wells with a 3rd party jack-up rig to accelerate development and cash flow
- Fully funded by an RBL with pricing set at Libor + 4.9%
- Epsilon project development through EPCIC contract with GSP
  - 3 production wells and a production platform Lamda

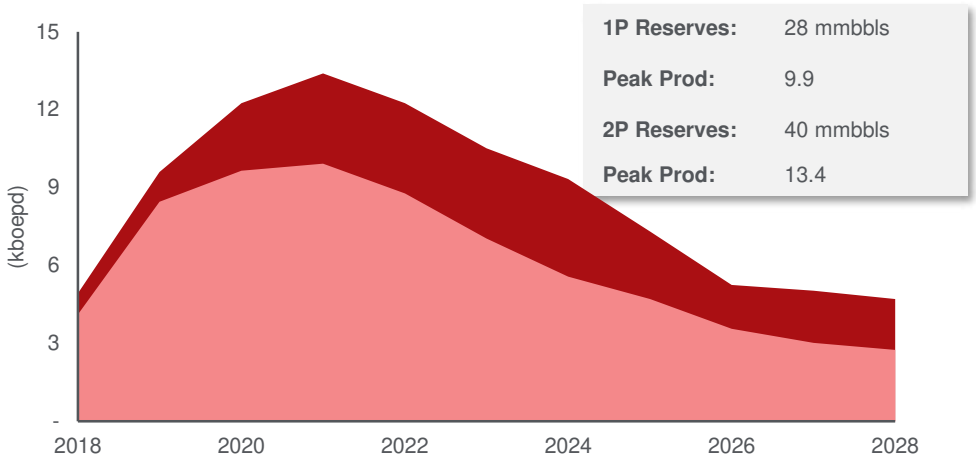
Efficient and Cost Conscious Operator



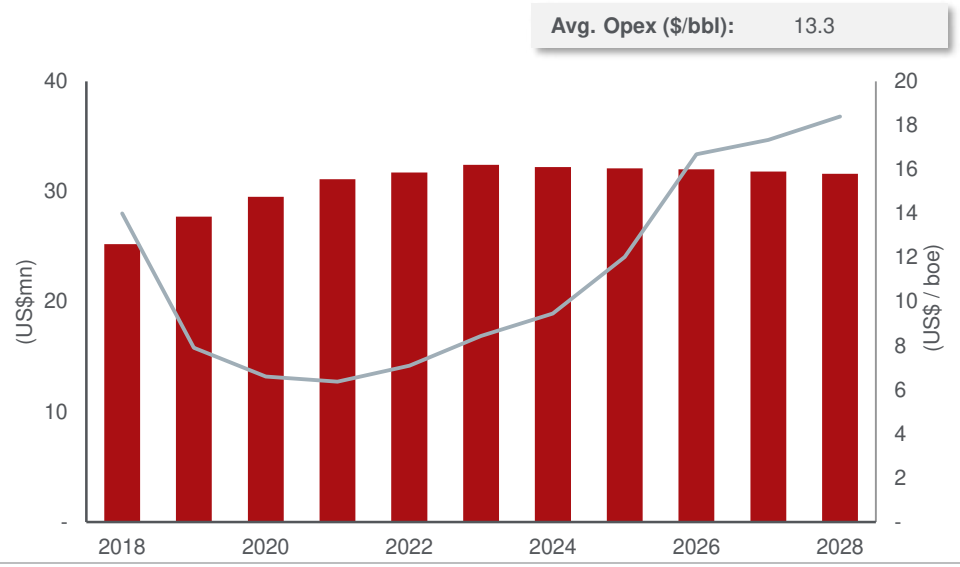
Source: Company, NSAI CPR.
Note: (1) SG&A shown on a gross basis excluding other income and expenses and exploration & evaluation costs.

Prinos Basin Operational Overview – CPR Case

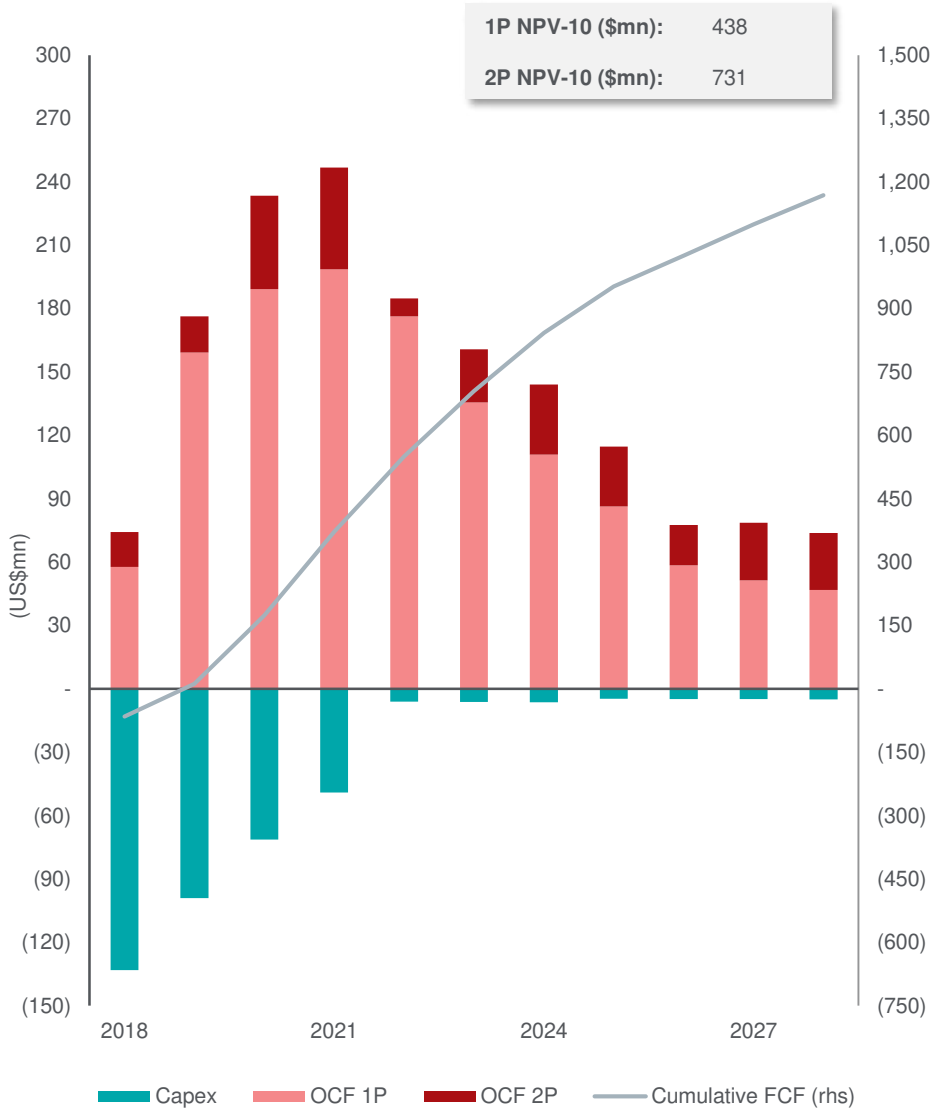
Production Profile



Opex



Unlevered FCF



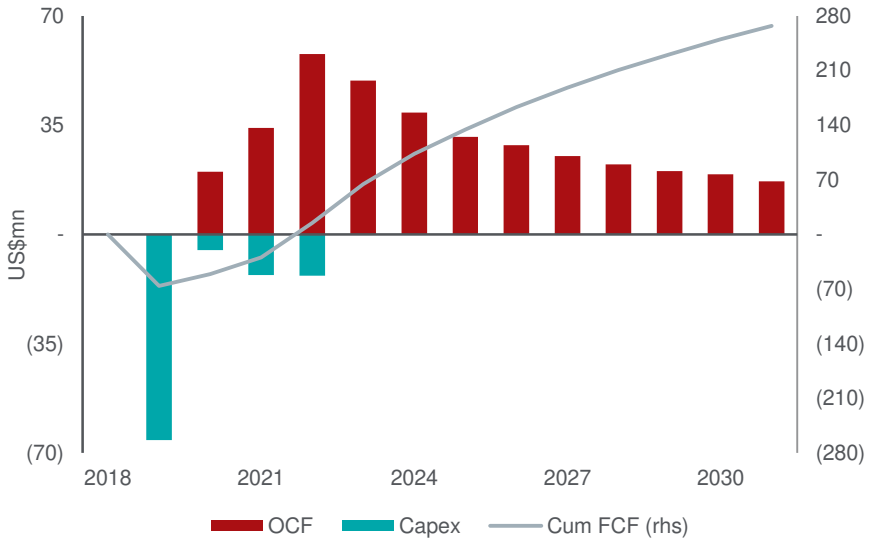
Source: NSAI CPR.
Note: Cash flows are in real terms as per NSAI CPR assumptions.

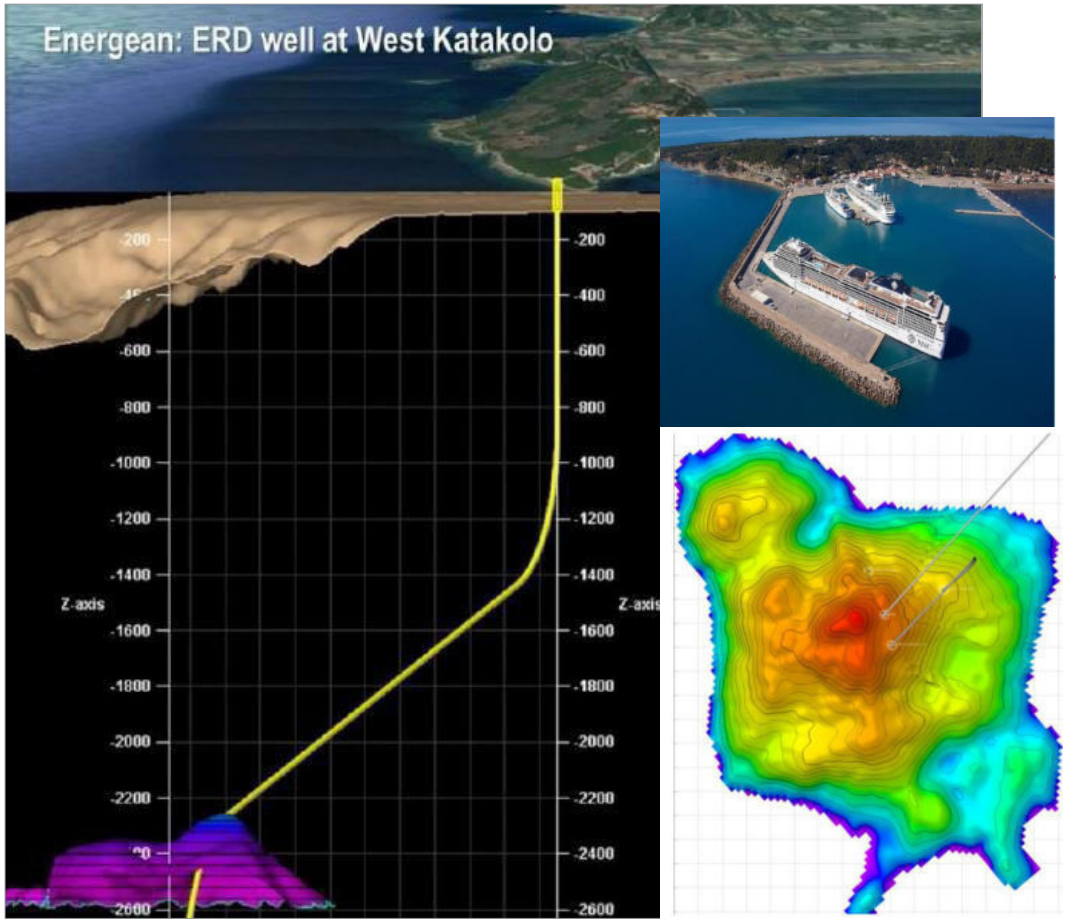
Additional Reserves at Katakolo

Overview

- 2P reserves of 10.5 mmbbls; Capex budget of $94mn
- West Katakolo reservoir is believed to be a dual porosity system (matrix, fractures and vugs), with an overlaying gas cap and an underlying aquifer
- 2 wells tested; plan is to drill the first pilot hole to be converted to an injection well in 2019
- Commencing environmental and social impact assessment to be submitted in 2018. Company intends to take FID upon approval
- First oil expected in 2020
- CPR NPV of US$ 114 mn

Unlevered FCF





Fiscal Terms

Development Period	25 years with two 5-year extension options
Royalty	2 - 20%
Corporate Tax	25%

Source: Company, Katakolo NSAI CPR.

Karish & Tanin – A Transformational Project in Israel

Key Highlights

World Class Assets

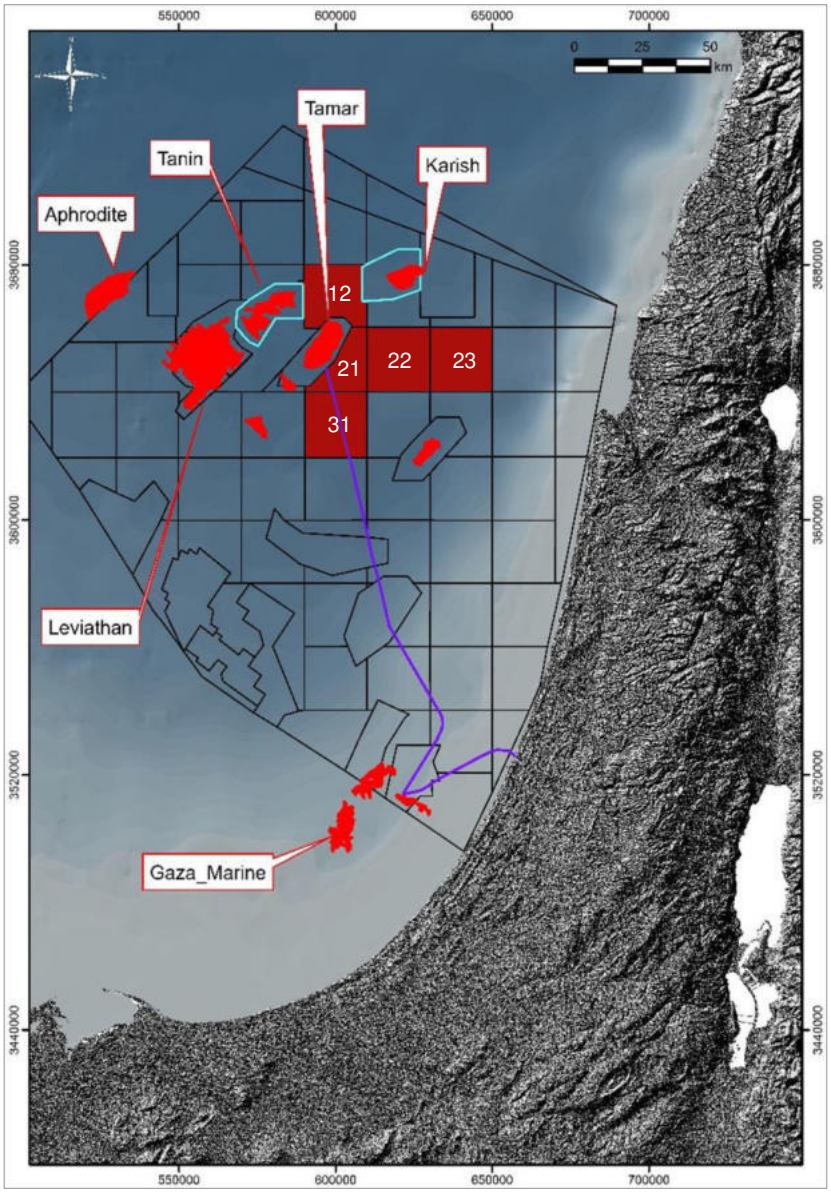
- Approximately 2.4 Tcf (67 bcm) gas
- 32.8 mmbbls hydrocarbon liquids(1)
- 1,700 metres water depth
- 75 km from shore

History

- Energean Israel 100% Operator
- Acquired from Delek August 2016
- Government Approval 26 December 2016
- New Lease Granted April 2017

Substantially De-risked Project

Regulatory	FDP approved August 2017	✓
EPCIC Contract	EPCIC $1.4bn contract (TechnipFMC)	✓
Drilling	3 firm, 5 optional wells (Stena Drilling)	✓
GSPAs	> 4.0 cm/yr (Bazan Group, OPC, ICL, Rapac, Dorad Energy)	✓
Project Financing	$1.275bn (Morgan Stanley, NATIXIS, bank hapoalim, SOCIETE GENERALE)	✓
FID	Taken March 2018	✓



Source: NSAI CPR, Company.
Note: (1) Best estimate 2C resource.

Karish & Tanin – More Than 4.0 Bcm/yr GSPAs Executed[1]

	Dalia Power Energies	EDELTECH		ICL	BAZAN GROUP	OPC	Rapac Communication & Infrastructure Ltd.	SUPERGAS
Volume	1.2 bcm/yr		2.6 bcm/yr				0.3 bcm/yr	0.1 bcm/yr
Tenor [2]	Min: 7 years -- Weighted Average: 16 years -- Max: 20 years							
Weighted Avg Take-or-Pay	75%							
Weighted Avg Current Price	$4.1 / mmbtu [3]							
Weighted Avg Floor Price	> $4 / mmbtu							

Energean Has Executed More Than 4.0 bcm/yr of Contracted Gas from Karish and Tanin [1]

Source: Company.
Note: (1) Based on Company's best estimate of volumes under GSPAs based on average volumes over life of contracts. Total best estimate 4.2 bcm/yr on an ACQ basis, 3.2 bcm/yr on take or pay basis, excluding Or GSPA. (2) Tenor presented includes Or GSPA. (3) Adjusted for inflation to make it comparable to current prices.

Karish & Tanin – TechnipFMC EPCIC and Stena Contracts Executed

Key Contract Terms

TechnipFMC $1.36 bn EPCIC Contract

- Two train new-build FPSO with an 8 bcm/yr capacity
- Low risk, lump-sum turnkey EPCIC contract – timing and performance risks borne by Technip FMC
  - Liquidated damages up to 12% of the contract value
- Project to be completed in early 2021 with handover scheduled in February
  - Testing and commissioning by Energean will shortly follow

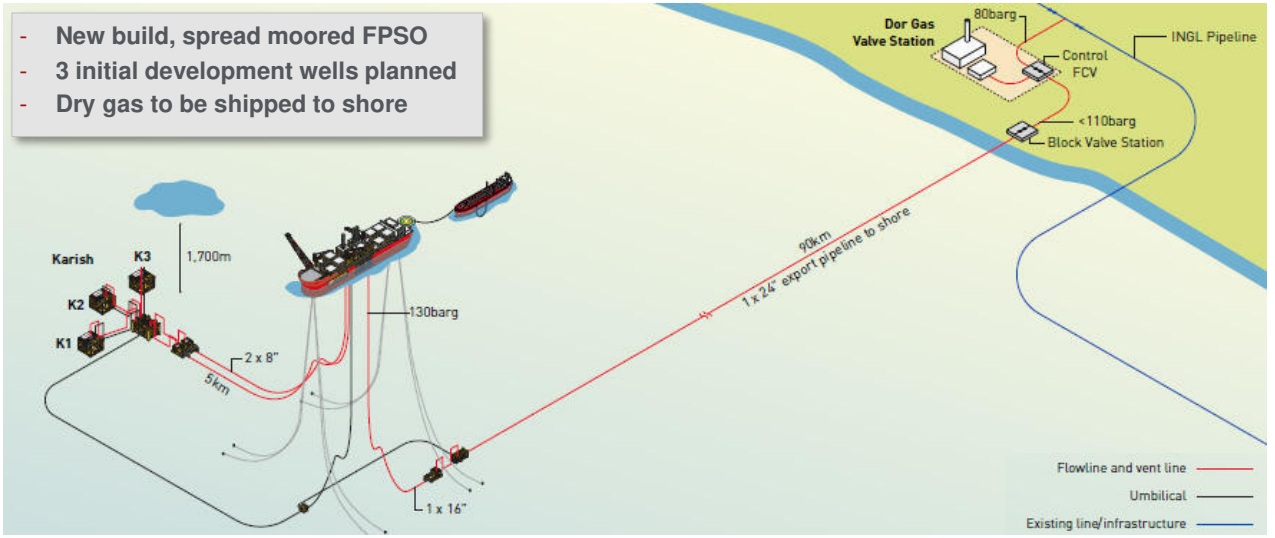
Stena Drilling Contract

- Contract in place for the development drilling of the Karish Field
  - Operating day rate of $140k agreed for the 3 firm wells
  - Energean holds option to drill 7 additional wells
- The Stena Forth drillship will be deployed to drill three development wells in Q1 2019
  - Significant step forward in the development and de-risking of the Karish field





Initial Development Phase



Project Finance Terms

Key Terms

- Senior secured first lien term loan facility parameters:
  - Size: Up to $1.275 bn
  - Interest: LIBOR + 3.75% (Months 1 – 12), + 4.00% (Months 13 – 24), + 4.25% (Months 25 – 36), + 4.75% (Months 37 – 45)
  - Maturity: 3 years and 9 months from signing date
  - Repayment: Bullet repayment on final maturity date
  - Commitment Fee: 30% of applicable margin

Project Finance Banks

Morgan Stanley

bank hapoalim

NATIXIS

SOCIETE GENERALE

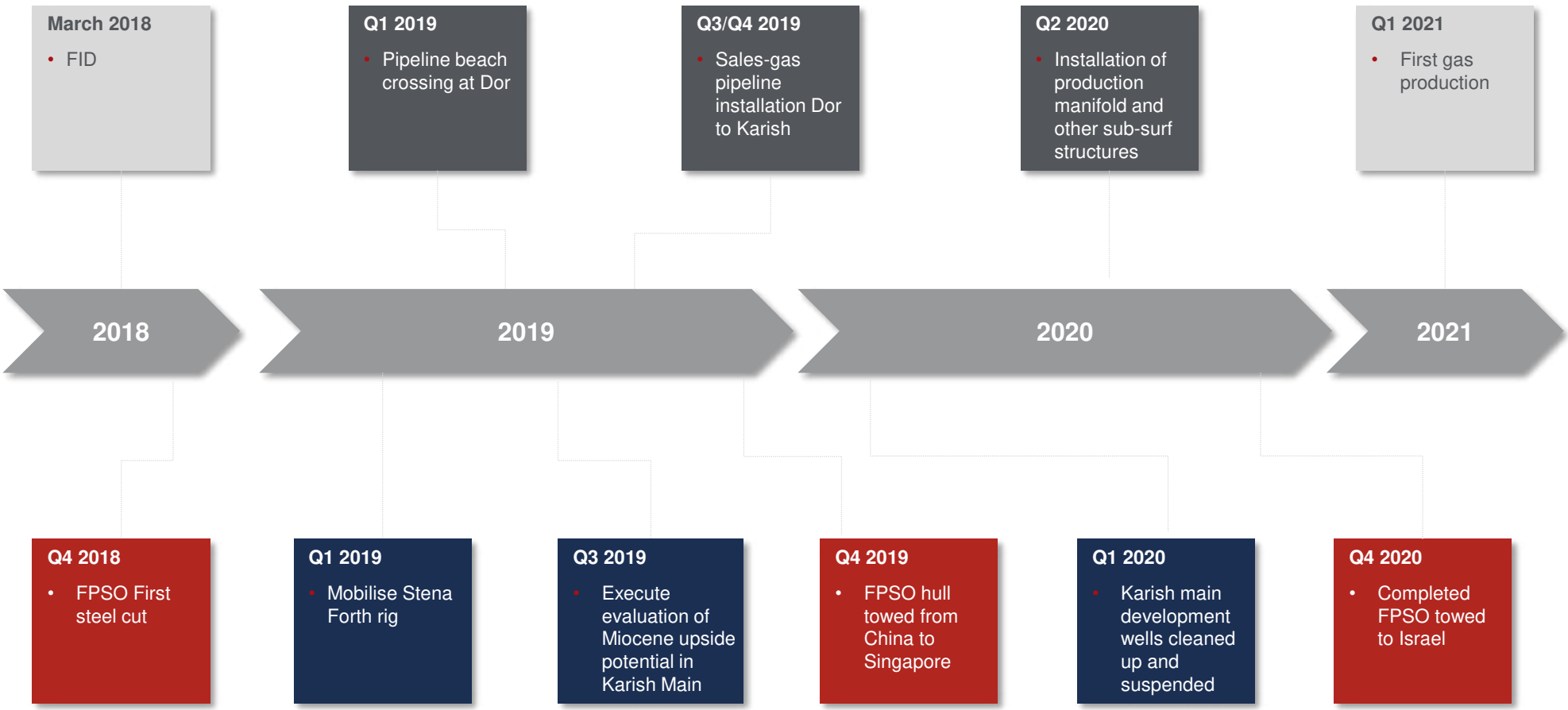
Sources & Uses

Sources	$MM	%
Construction Loan	1,275	*66*
IPO Proceeds for Karish Development Capex Commitments	405	*21*
Shareholder Equity	120	*6*
Existing Investment	*60*	*3*
Kerogen New Equity Investment	*60*	*3*
Contingent Equity	125	*6*
Total Sources	**1,926**	***100***
Technip Deferred Payments	140	
Total Sources (incl. Deferred Payments)	**2,066**	

Uses	$MM	%
Capex for Phase 1	1,605	83
Drilling	*123*	*6*
FPSO (Expected Technip EPCIC)	*905*	*47*
Subsea & Pipelines (Expected Technip EPCIC)	*517*	*27*
Owners Costs	*116*	*6*
Phase 1 Contingency	*84*	*4*
Technip Deferred Payments	*(140)*	*(7)*
Pre-FID Costs	60	3
Lease Payments to Seller	55	3
Interest During Construction	146	8
Transaction Fees and Expenses	60	3
Total Uses	**1,926**	***100***
Technip Deferred Payments	140	
Total Uses (incl. Deferred Payments)	**2,066**	

Source: Company.

Key Milestones to Karish and Tanin First Gas



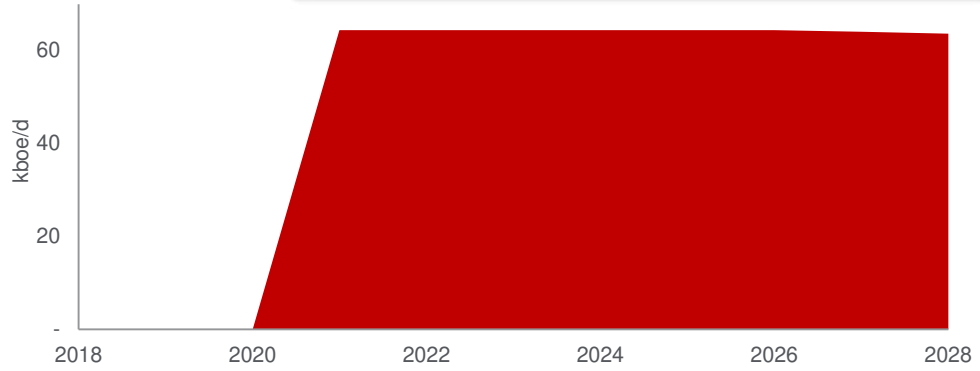
Source: Company.

Karish and Tanin Operational Overview – CPR Case(1)

2C Net Production Profile by Asset

WI: 70%

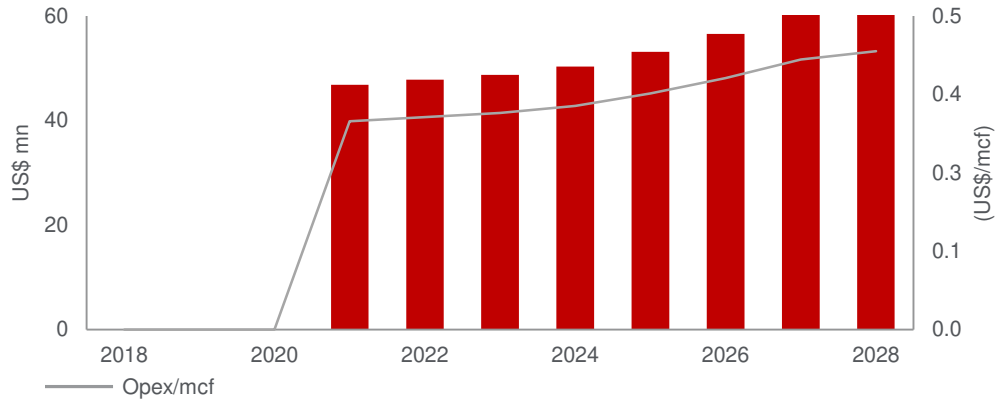
Net 2C Resources:	1.7 Tcf gas, 23 mmbbls hydrocarbon liquids
Peak Net Prod.:	64.4 kboe/d



Opex

WI: 70%

Opex/mcf:	$0.4/mcf
Cum. Net Opex to 2031	$623 mn



Unlevered FCF

WI: 70%

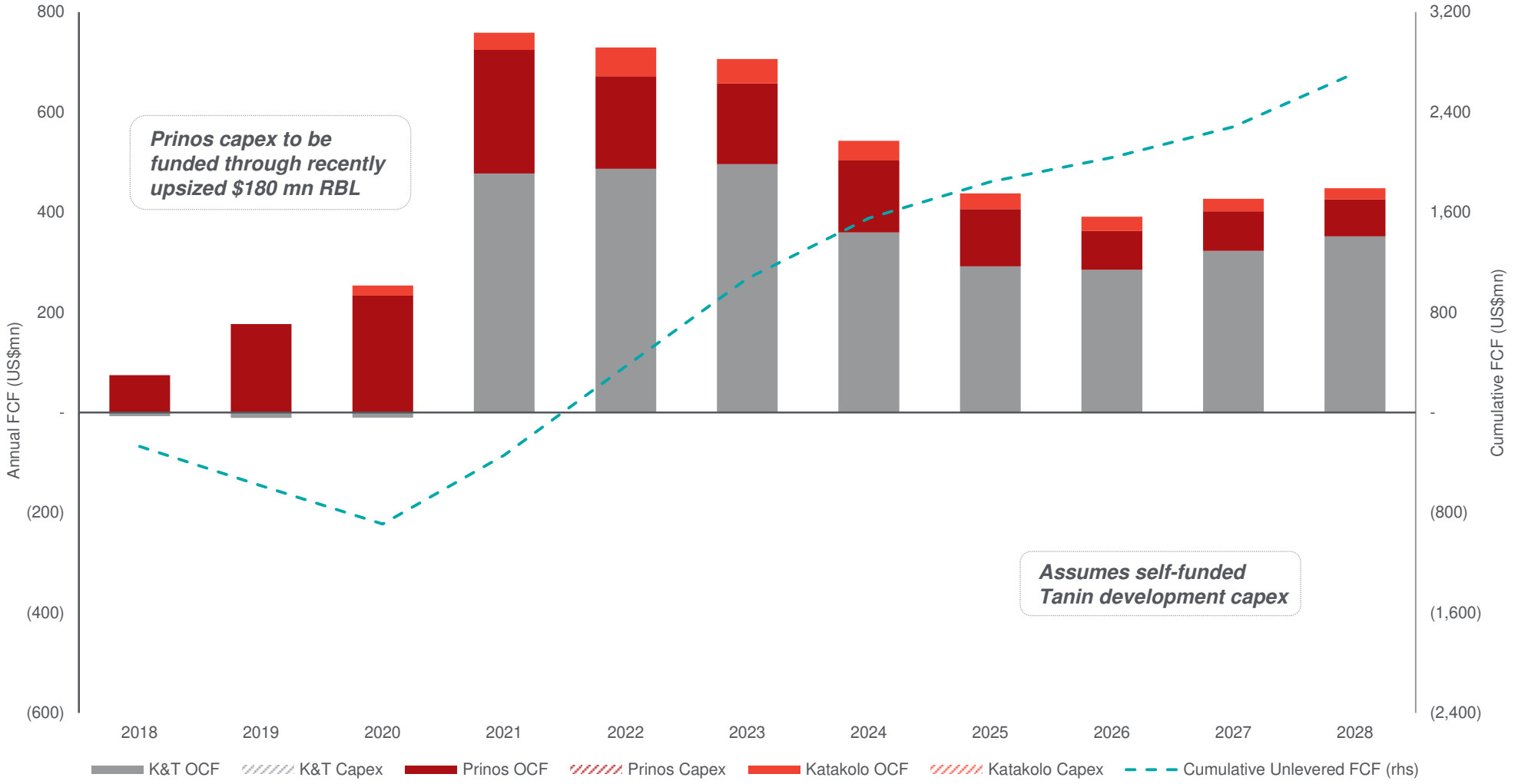
NPV-10 ($bn)(2):	0.8



Source: NSAI CPR.
Note: (1) Figures shown are net to 70% stake. (2) 2017 asset value, as stated in the NSAI CPRs and calculated as the present value of the asset net cash flows discounted at 10%.

De-Risked Portfolio Poised for FCF Generation

Karish and Tanin(1) and Greece Annual Unlevered FCF



Note : (1) 70% WI, based on NSAI CPR.
Source: NSAI CPR for Karish and Tanin, Prinos Basin and Katakolo.

Exploration Upside in Western Greece Validated by Repsol

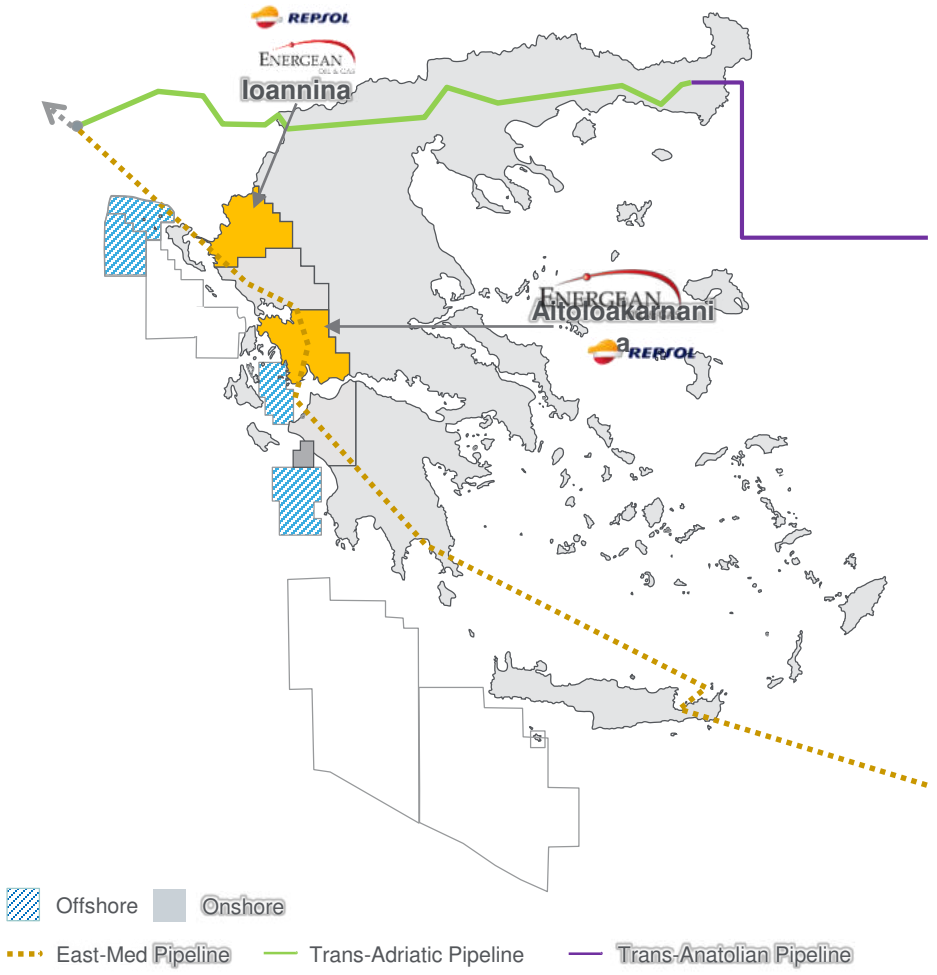
Repsol Carries Energean for 90% of Expenditures up to $49.9 mn

Energean's Onshore JV with Repsol

- 60 / 40 joint venture with Repsol as the operator
- Initial exploration phase run through 2019 for Ioannina and 2021 for Aitiloakarnania
  - 205 mmboe gross unrisked prospective resources
  - Repsol has started seismic exploration activities
  - €15.1 mn commitment
- Next exploration phases run through 2021 for Ioannina and 2023 Aitoloakarnania
  - Total commitment of approximately €23 mn
  - Decision to enter next exploration phase expected in Oct 2019 (only Ioannina)

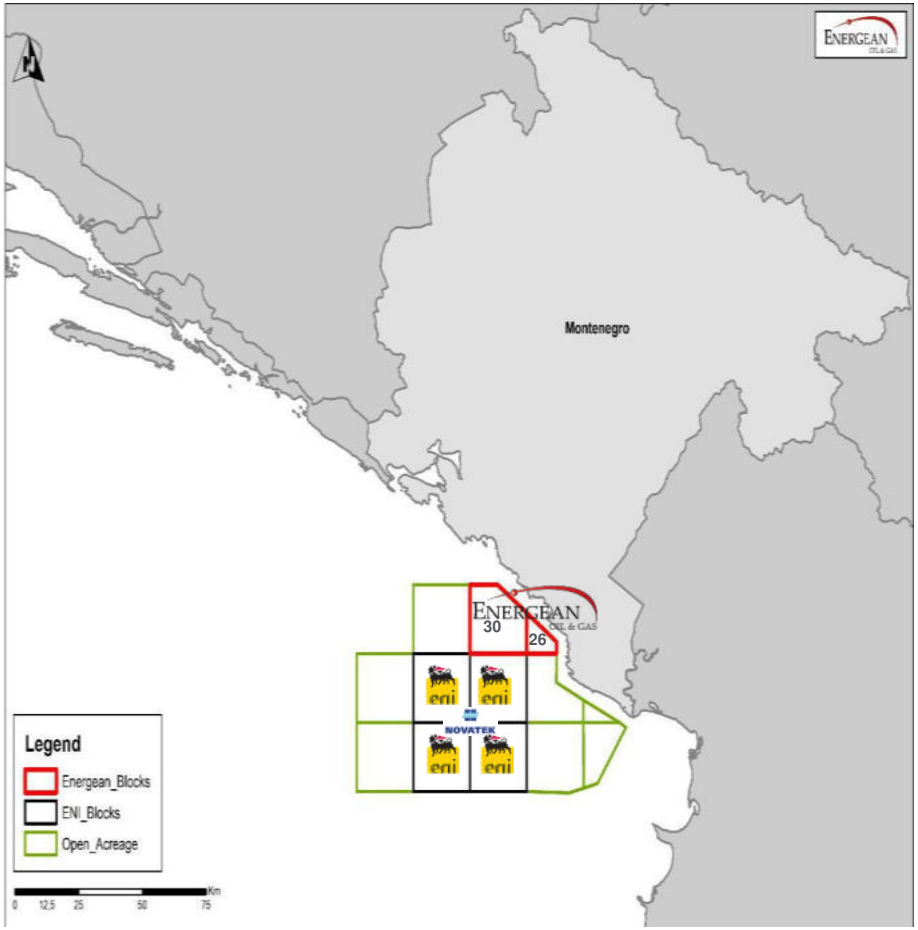


Repsol Carry on Greek Onshore Blocks



Source: Company.

Further Upside in Montenegro



Unrisked Prospective Resources	Gas *(TCF)*	Liquids *(mmbbl)*
Montenegro	**1,8**	**144**

Montenegro Key Highlights

- Blocks 4218-30 and 4219-26 officially awarded in March 2017 (Energean 100%)
  - Surface area 338 km^2 / water depth 5 – 75 m
  - Cretaceous Carbonates represent the main reservoir target
  - Secondary Pliocene and Oligocene gas play
- 3 year 1st exploration phase
  - Mandatory work program: 3D seismic acquisition covering two blocks + G&G studies + training
  - 100% cost during initial exploration phase estimated at $5 mn
- Optional second exploration period of 4 years: 1 firm exploration well of not less than 2,800 m
- ENI has 4 blocks to the south
  - Work commitment is expected to comprise full 3D coverage and 2 wells with 1 well to be drilled to test the Cretaceous platform carbonates (TD ~ 6 km)

Source: Company.

Karish & Tanin Exploration Plus 5 New Blocks in Israel Provide Further Upside

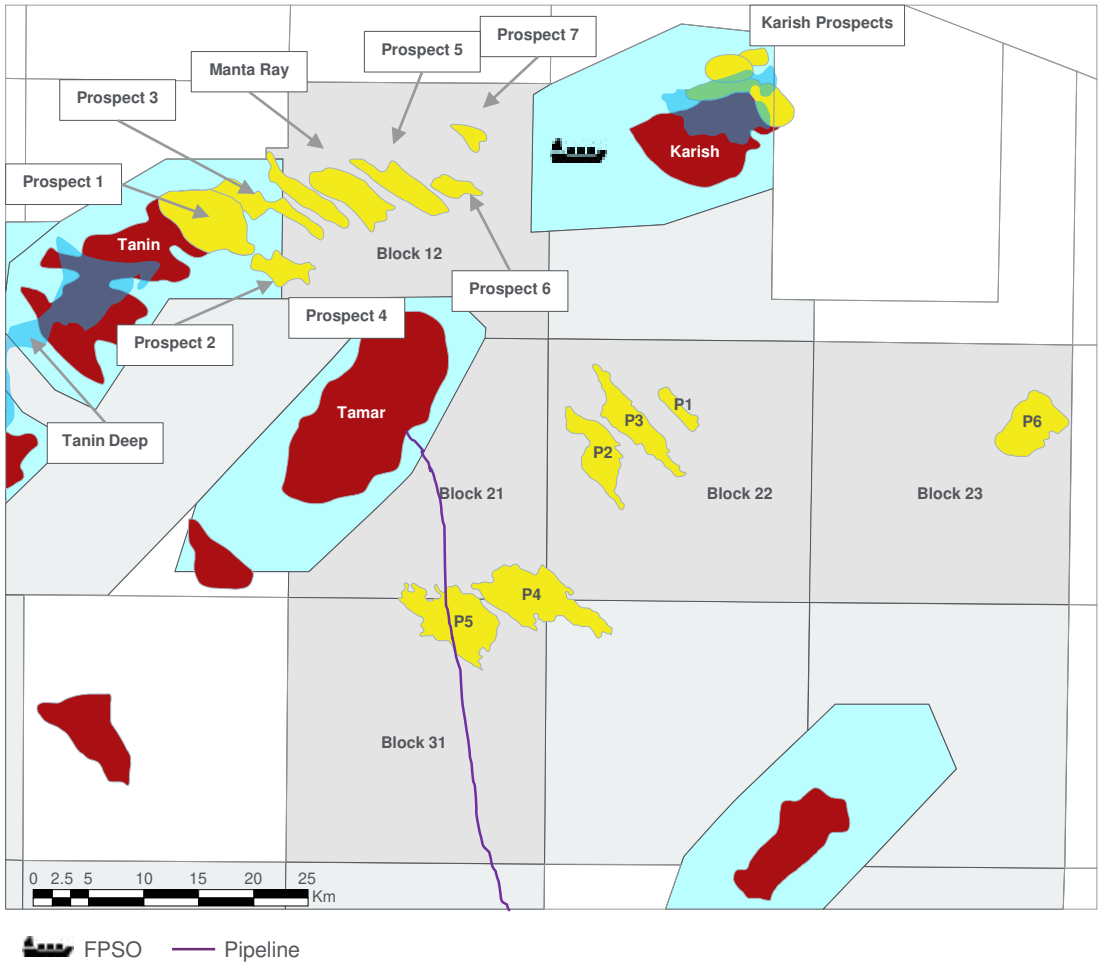
Israel Bid Round: December 2017

- The Israeli Petroleum Council awarded five out of six exploration licenses in the First Israeli Offshore License Round to Energean
  - Blocks Awarded: 12, 21, 22, 23 and 31
  - Initial exploration period: 3 years
- The licenses are located adjacent to the Karish and Tanin fields
- In the event of any economic hydrocarbon discoveries, the fields could be developed via tie-backs to the Karish and Tanin FPSO
- Energean's exploration spending commitments are expected to be ~$6.5mn over the next three years
- Under the terms of the tender, the initial test drilling in each field must begin by 2020
- Proposed work program for all blocks includes:
  - Re-processing existing 3D data on block
  - Acquiring new 3D seismic survey

Unrisked Prospective Resources(1)

	Gross		Net (70%)		
Hydrocarbon Liquids/Gas	Liquids (mmbbl)	Gas (bcf)	Liquids (mmbbl)	Gas (bcf)	Pg(2) (%)
Karish	31	2,003	22	1,402	72
Tanin	40	444	28	311	56
K&T Total	71	2,447	50	1,713	69

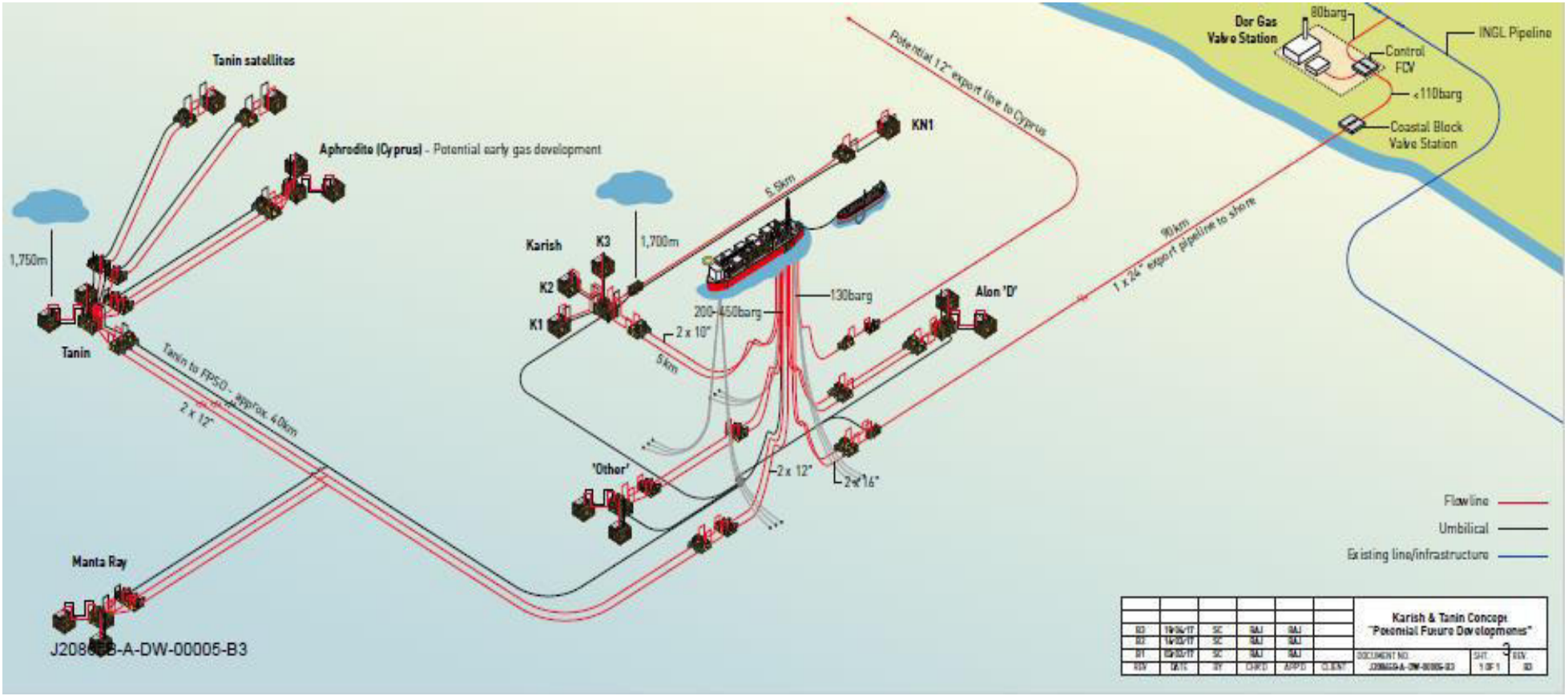
Overview of Block Locations



Source: Company
Note: (1) Certain figures have been subject to rounding adjustments. Accordingly figures shown as totals in certain tables may not be an arithmetic aggregation of the figures that precede them. (2) Weighted average by unrisked prospective resources

Karish & Tanin FPSO – A Hub to Commercialise Other Fields

Overview of Karish & Tanin FPSO Potential Tie-Ins



Source: Company.

Israeli Gas Demand Expected to Grow Significantly

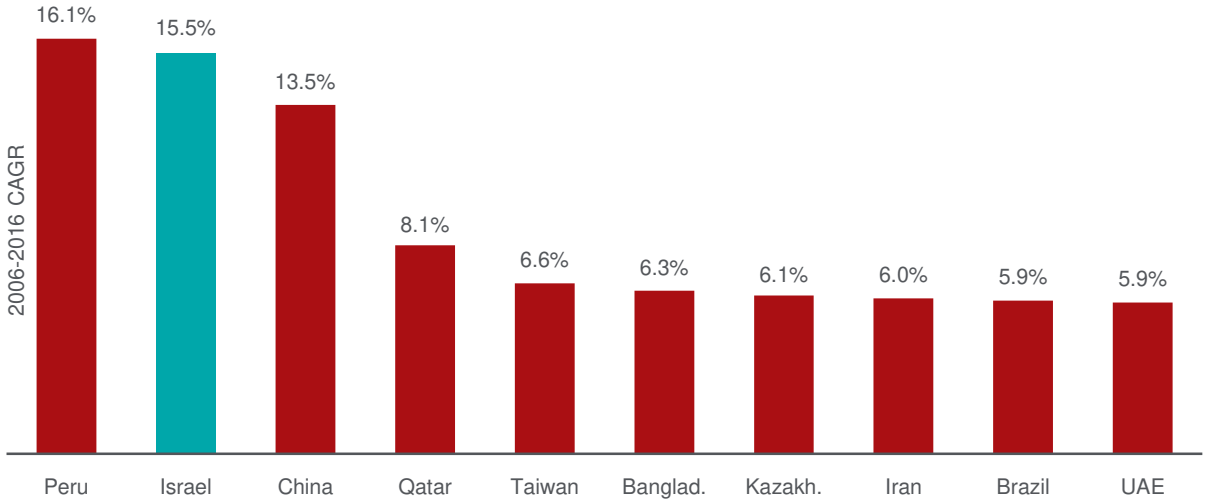
Key Highlights

- Over the last decade Israel natural gas demand has been amongst the fastest growing globally
- Future demand is forecasted to increase substantially primarily driven by electricity sector
- Regulatory developments will be important catalysts supporting future demand growth

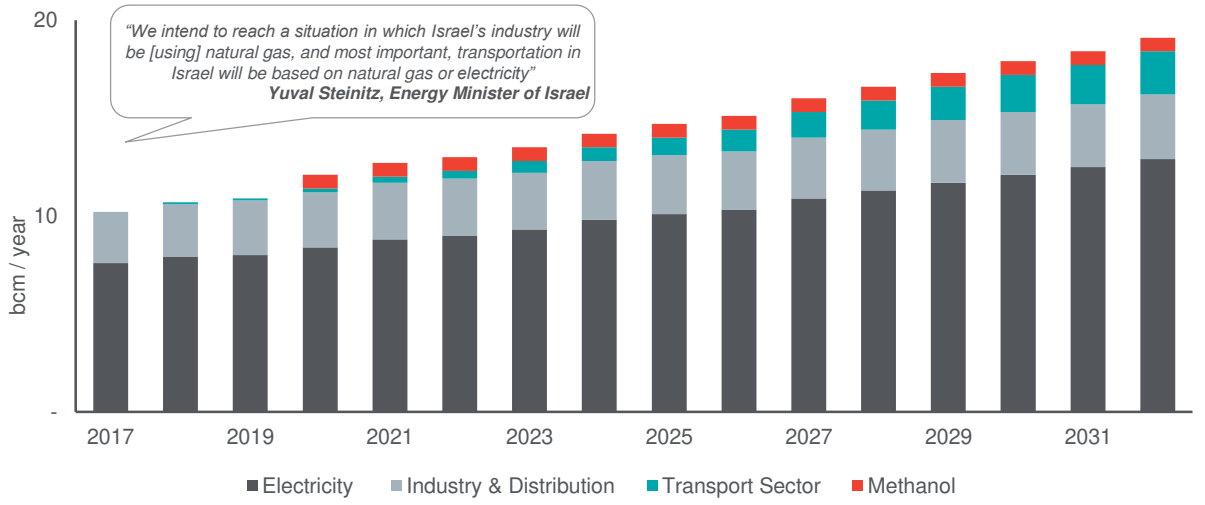
Israeli Regulatory Support

- Israeli Electric Corporation required to reduce coal generation post 2017
- August 2016 decision to close the 1,440 MW Orot Rabin coal-fired plant by June 2022 and replace it with gas-fired generation
- Incentivise light industrial customers to switch from oil to gas
- Incentivise CNG stations and electric vehicles
- Government funded deployment of a new natural gas distribution system

Gas Demand Increase 2006-2016 CAGR – Top 10 Countries Globally



Israeli Natural Gas Demand by Sector

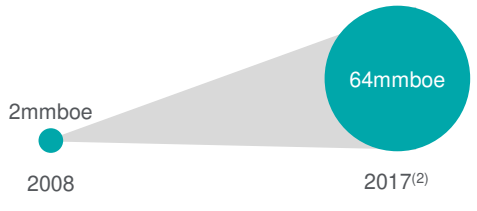


Source: Israeli Electric Corporation; Israeli Ministry of Energy; BP Statistical Review of World Energy June 2017.

Proven Track Record of Acquiring, De-risking and Financing Projects

M&A

✓ Prinos Reserves and Resources (1)



✓ Karish & Tanin Development (2)

- Acquisition of a stranded gas field in Dec 2016
- FID of a 2.4 TCF development taken

✓ Western Greece Farm-Out

- Repsol carries 90% of expenditure up to $49.9 mn for both blocks (60% thereafter)

REPSOL

Contracts

✓ GSPAs

- 4.2 Bcm/yr contracted
- Weighted avg current price(3): $4.1 / mmbtu

Dalla Power Energies, ICL, BAZAN GROUP, OPC, SUPERGAS, Rapac

✓ FPSO and Drilling Contracts

- TechnipFMC lump-sum, turnkey EPCIC contract of c. $1.36 bn
- Stena Drilling contract for the development drilling of Karish field

TechnipFMC, Stena Drilling

✓ BP Offtake

- Long term offtake signed until July 2025, or delivery of 25 mmbbls of oil

bp

Financing

✓ $1.275 bn Project Financing

Morgan Stanley, bank hapoalim, NATIXIS, SOCIETE GENERALE

✓ $180 mn Prinos RBL

European Bank, EximBank Romania, INTESA SANPAOLO BANK Romania, Black Sea Trade & Development Bank

✓ Long Term Capital Providers

- Third Point invested since 2013
- Kerogen since 2016
- EBRD since 2016

THIRD POINT, KEROGEN Capital, European Bank

Source: NSAI CPR, Company.
Note: (1) Includes 2P + 2C resources as per respective CPRs .(2) 2C resources as per NSAI CPR as per 31 October 2017. (3) Adjusted for inflation to make it comparable to current prices.

Near Term Catalysts Post IPO

2018 - 2019

Production



- Drill 8 wells in Prinos licence
- Epsilon field on-stream

Target 2020 production of >9 kbopd

Development



- Drill 3 wells in Karish
- Discretionary exploration well
- Potential to contract additional long-term off-take volumes and utilize up to 8 bcm/yr of Karish FPSO capacity

Target unrisked upside of circa 1.7 TcF(1)

Exploration



- Potential to increase and de-risk current unrisked prospective resources of c.0.9 bnboe
- 90% of W. Greece exploration costs carried by Repsol, up to $49.9 mn
- 3D seismic and G&G studies on the Montenegro blocks
- 3D seismic on new Israeli blocks

Strengthen and Grow the East-Med E&P champion

Note: (1) Subject to resource availability.
Source: Company.

Post Period Developments

- Took FID on Karish and Tanin project
- Signed US$1.275billion senior credit facility for Karish and Tanin
- Premium Listing on the LSE - Global offer raising US$460m
- Signed US$180m RBL facility with EBRD and other institutions
- March 2018 – Group completed subscription for additional shares in Energean Israel for US$266.7M, increasing stake to 70%
- Awarded TechnipFMC integrated EPCIC for full field development of Karish
- Appointed Stena Drilling for 3 firm development wells in 2019 plus 7 additional optional wells
- Signed extension to BP offtake agreement to November 2025
- Successfully completed c.4km extended reach well in Prinos North – currently producing at c. 1,000 bpd on 41% choke
- Production averaged 3,673 bopd in Q1 2018, an increase of 31.6% year-on-year (Q1 2017: 2,790 bopd) and 7.9% quarter-on-quarter (Q4 2017: 3,405 bopd)
- Progressed plans for Secondary Listing on Tel Aviv Stock Exchange
- Israeli Supreme Court dismissed petition against Karish development

Outlook

- Priority for 2018 is project delivery
- Group expects to complete several project milestones on Karish and Tanin
  - Submission of Karish Lease Environmental Document to Israeli regulator
  - Completion of detailed design for topsides and hull
  - TechnipFMC to commence fabrication of FPSO hull and topsides (Q4)
- Five development wells on Prinos licence in 2018
- Group expects average production rate of 4,000-4,500 bopd from Prinos

Well positioned to capitalise on future growth opportunities in Eastern Mediterranean

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Appendix

Historical Financial Results Highlights

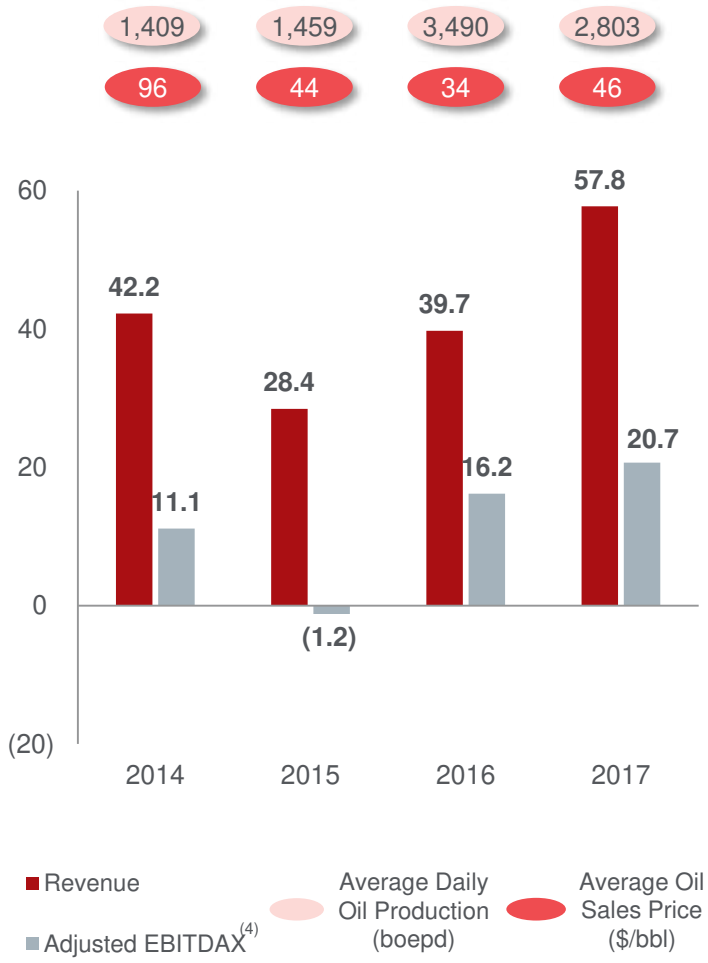
Financial Highlights

$ mn, unless otherwise stated	2015	2016	2017
Realised Sales Price ($/bbl)	44	34	46.7
Production (boepd) [1]	1,459	3,490	2,803
Revenues	28.4	39.7	57.8
Adjusted EBITDAX[2]	(1.2)	16.2	20.7
Cost of Production	(21.7)	(24.3)	(25.3)
Cash Flow from operating activities	(2.8)	15.2	29.1
Capital Expenditure [3]	(49.2)	(110.7)	(70.3)

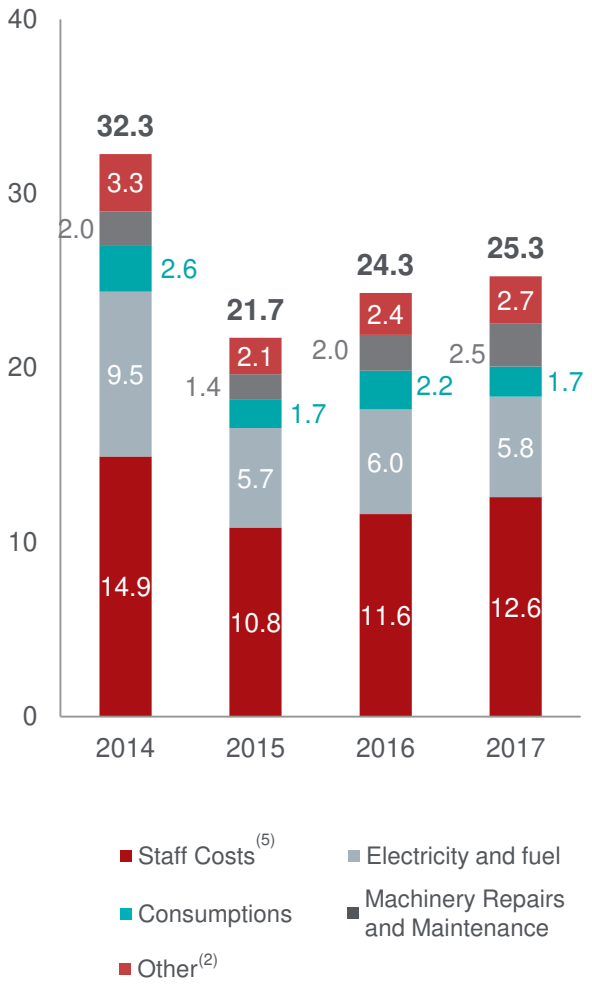
Notes: (1) Only oil production volumes shown as gas produced at the Prinos basin is not sold. (2) Adjusted EBITDAX is calculated as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange (loss) / gain and exploration and evaluation expenses. (3) Capex includes cash purchases of PP& and intangible assets.

Historical Financial Results Highlights (cont'd)

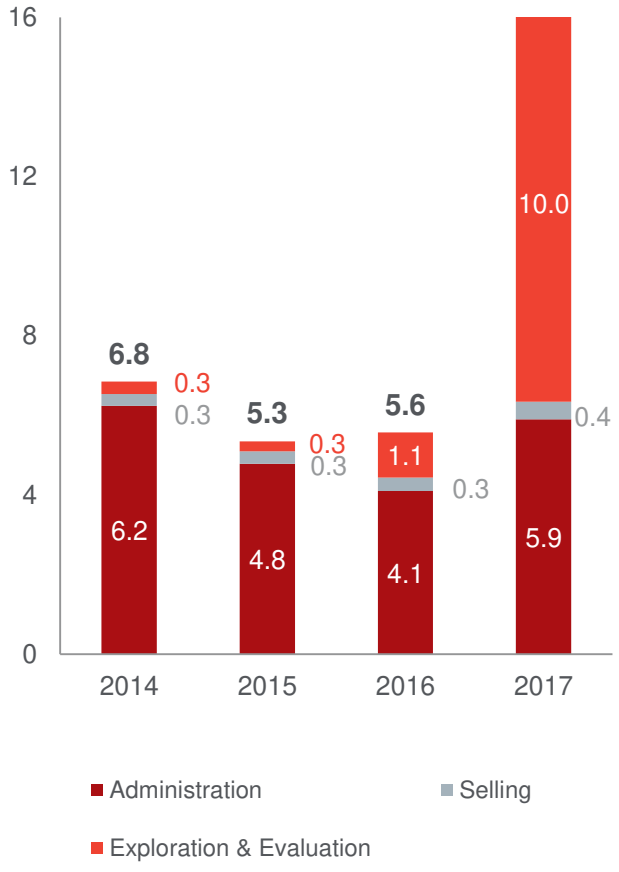
P&L Highlights (US$mn)



Cost of Production(1) Breakdown (US$mn)



SG&A(3) Expenses Breakdown (US$mn)



Source: Company information
Notes: (1) Cost of production shown does not include the costs associated with the changes of inventory, $5.0mn for 2017, ($5.0mn) for 2016, $3.1mn for 2015 and ($7.4mn) for 2014 and the depreciation costs, $17.6mn for 2017, $21.2mn for 2016, $7.3mn for 2015 and $7.4mn for 2014. (2) Other costs include Subcontracted Work, Insurance, Sundry Expenses, Royalties and Other Professional Fees and Other Expenses. (3) SG&A shown on a gross basis excluding other income and expenses. (4) Adjusted EBITDAX is calculated as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange (loss) / gain and exploration and evaluation expenses. (5) Staff costs include cost of services and cost of production.

IPO Sources and Uses Summary

Sources & Uses	US$460mn

Sources	(US$mn)	(%)
Primary IPO Proceeds	460	*100*
Estimated Total Sources	**460**	***100***

Uses	(US$mn)	(%)
Karish Development Capex commitments (incl. Contingencies)	405	*88*
General Corporate Purposes	30	*7*
Transaction Fees and Expenses	15	*3*
Repayment of Bridge Financing	10	*2*
Total Uses	**460**	***100***

Source: Company.

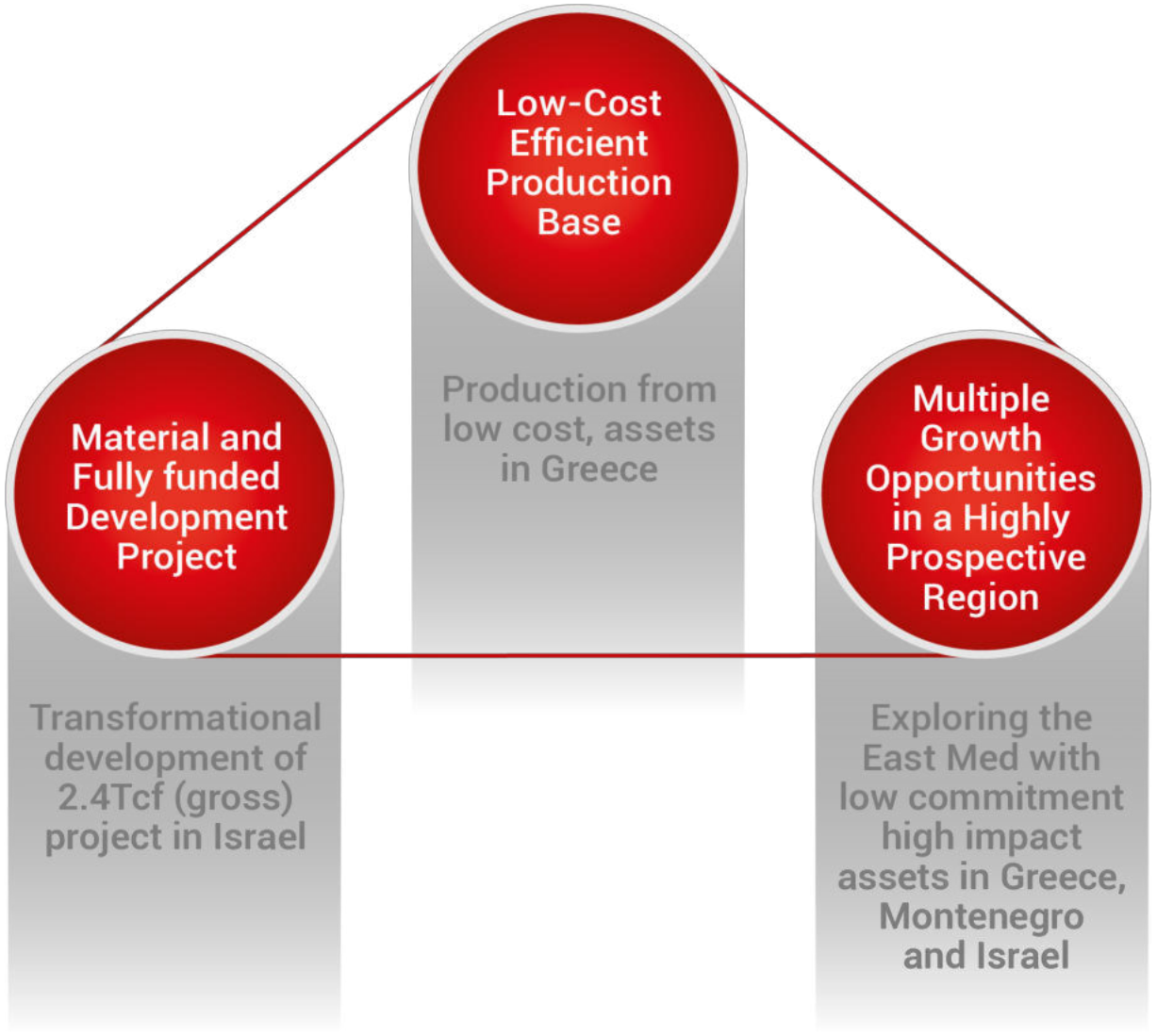
July 2018

ENERGEAN
OIL & GAS



FTSE 250 E&P Company Focused On The Highly Attractive Eastern Mediterranean Region

Vision: Premier Eastern Mediterranean Independent E&P Player



- Disciplined capital allocation
- Management team with proven track record
- Committed and invested management aligned with shareholders

Energean At A Glance

Management



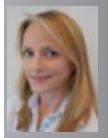
Mathios Rigas
Chairman & CEO



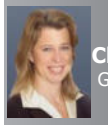
Panos Benos
Chief Financial Officer



Dr. Steve Moore
Chief Growth Officer



Kate Sloan
Head of Investor Relations



Michelle Churchward
Group General Counsel

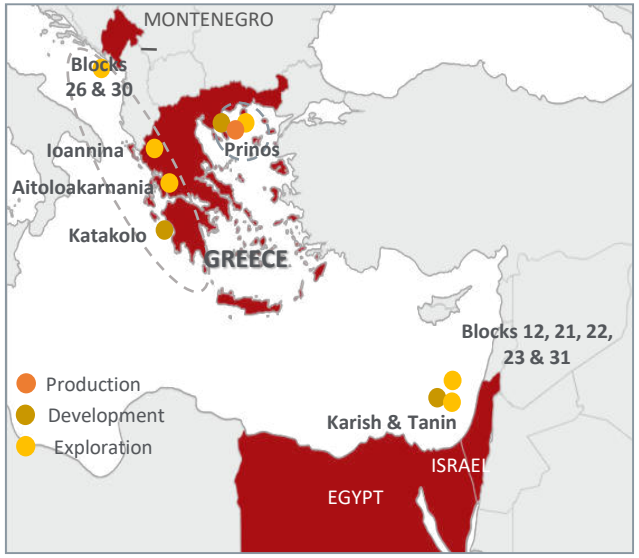


David Donaldson
Prinos Asset Manager

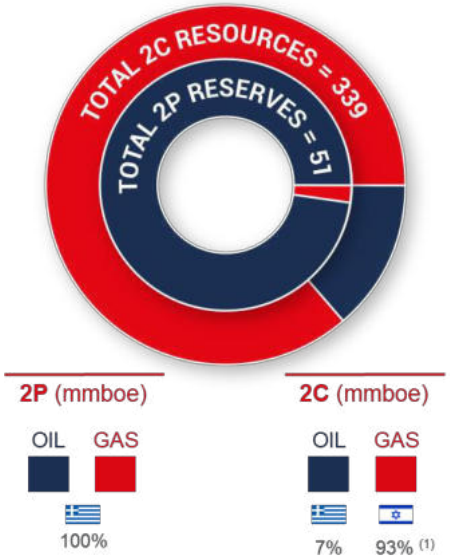


Dennis Anestoudis
Exploration Manager

Focus on the East Med



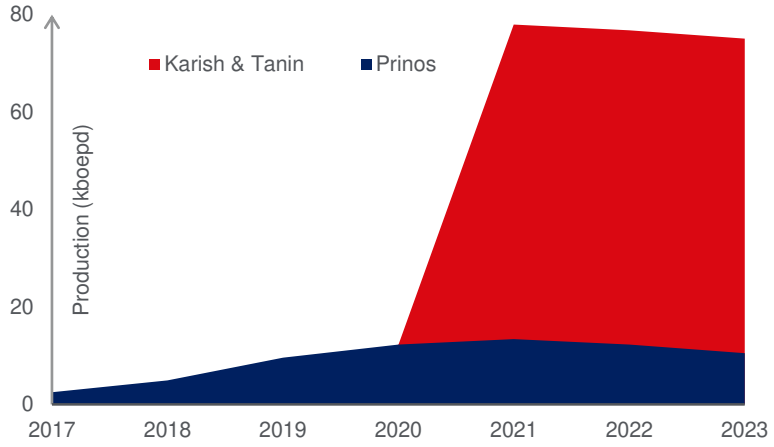
Focus on Gas



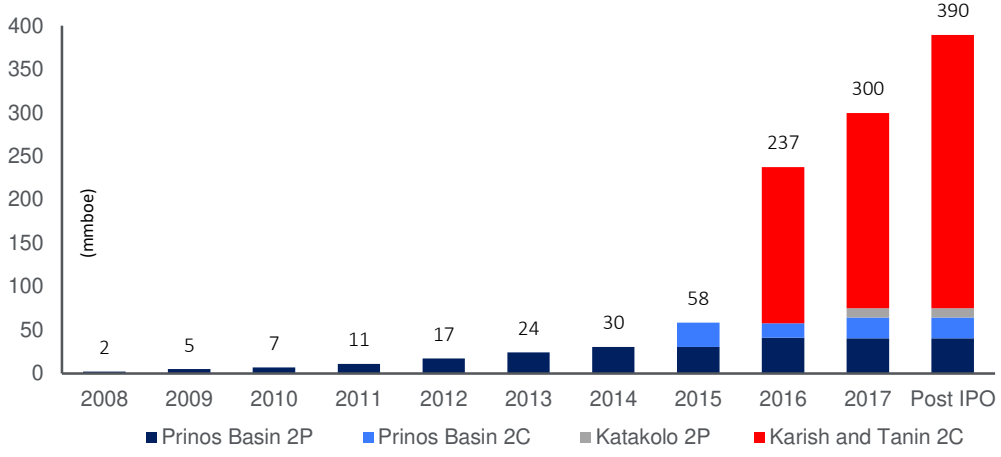
Delivering a 2.4 Tcf Project in Israel

Regulatory	FDP approved August 2017 ✓
EPCIC Contract	Lump sum turnkey EPCIC – TechnipFMC ✓
Drilling	4 firm, 6 optional wells – Stena Drilling ✓
GSPAs	4.2 bcm/yr (16yr av) $12bn revenue ✓
Project Financing	$1.275bn – Morgan Stanley, bank hapoalim, NATIXIS, SOCIETE GENERALE ✓
Equity	$460 million raise through Premium LSE IPO – Fully funded project ✓
FID	Taken March 2018 ✓

Production



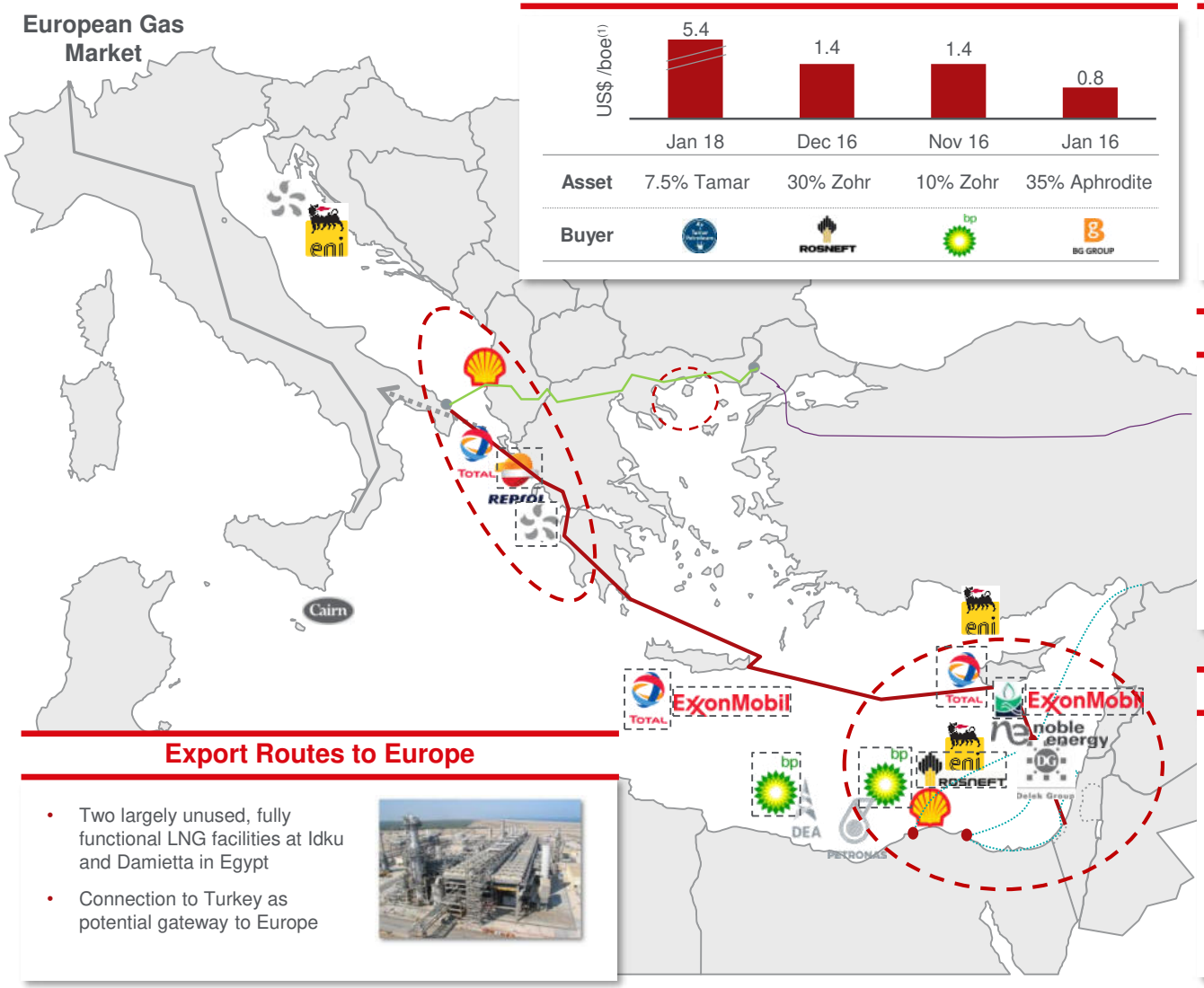
Reserves Growth History



Note: (1) 2C resource in Israel will be converted into 2P reserves on audit due to FID being established

Eastern Mediterranean- A Hive of Activity

European Gas Market

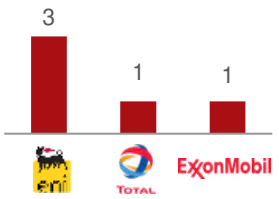


Increasing M&A Activity

US$/boe[1]	5.4	1.4	1.4	0.8
	Jan 18	Dec 16	Nov 16	Jan 16
Asset	7.5% Tamar	30% Zohr	10% Zohr	35% Aphrodite
Buyer		ROSNEFT	bp	BG GROUP

Cyprus

Future exploration wells in 2018



"Calypso 1 is a promising gas discovery and confirms the extension of the Zohr like play in the Cyprus EEZ […] that could contain more than 230 BCM of gas, and contains not less than 170 BCM"

Claudio Descalzi, ENI CEO

East Mediterranean Pipeline

- Gas pipeline connecting East Med via Greece and Italy with the European gas network
- MoU signed between Israel, Greece, Italy and Cyprus supporting the pipeline construction
- Classified as European Project of Common Interest with EU sponsoring 50% of pre-FEED costs
- Targeted project completion by 2025

Export Routes to Europe

- Two largely unused, fully functional LNG facilities at Idku and Damietta in Egypt
- Connection to Turkey as potential gateway to Europe

Israel / Egypt Gas Deal

- Israeli firms signed a $15 bn deal to export gas to Egypt from Leviathan and Tamar
- Agreement to supply 64 bcm of gas over 10 years
- Implied price of c.$6.6/mmbtu

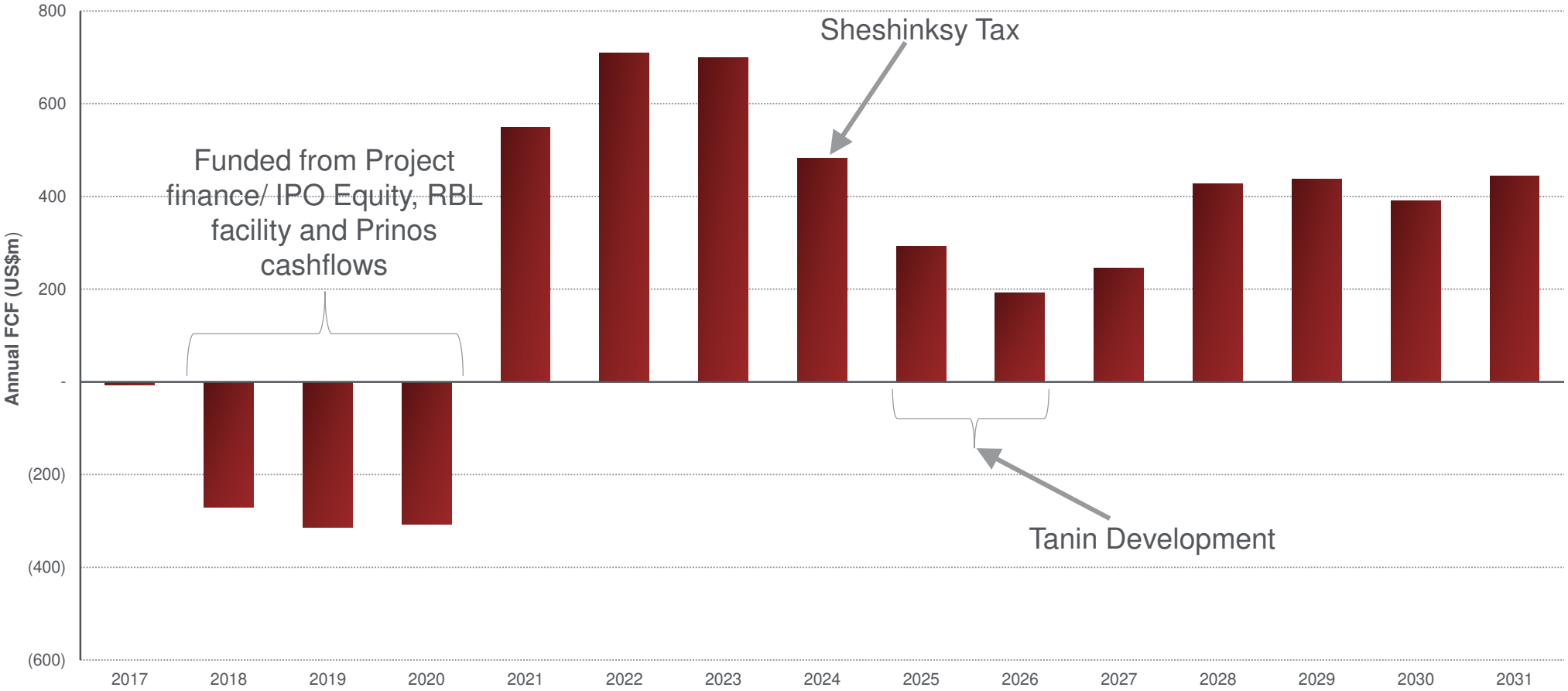


DOLPHINUS

Energean Focus Regions | Newcomers | Trans-Anatolian Pipeline | Trans-Adriatic Pipeline | East-Med Pipeline | Other Proposed Pipelines | Egypt LNG plant

Note: (1) Transaction value / boe. Source: Company Filings, Herold.

De-Risked Portfolio Poised for FCF Generation



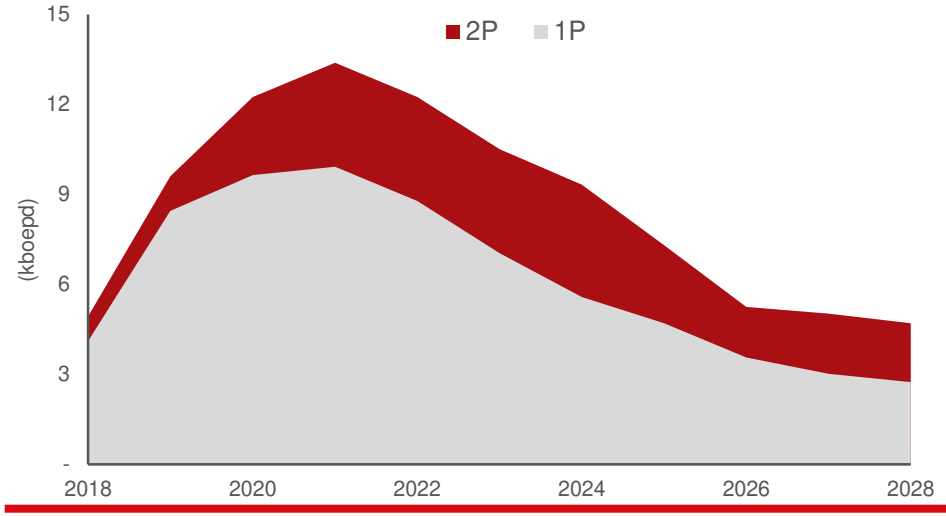
Note: (1) 70% WI, based on NSAI CPR, (2) Oil Price: 65 $/bbl, Gas Price: 4.25 $/mmbtu Source: NSAI CPR for Karish and Tanin, Prinos Basin and Katakolo.

Low Cost Stable Greek Production Base

Stable Production Base Around Prinos Basin

- 40.5 mmboe of 2P reserves and 23.8 mmboe of 2C resources
- 100% WI for all fields
- Significant operation leverage with 2018 Opex of $17/bbl, heading towards $9/bbl by 2021 in 2P profile, supported by favourable fiscal terms
- Owned infrastructure offers operational flexibility
- No abandonment liability for pre-existing infrastructure
- Long term offtake agreement signed with BP until November 2025 or delivery of 25 mmbbls of oil to BP
- 2018 target production: 4 - 4.5 kbopd
- Fully funded via $180mn RBL facility

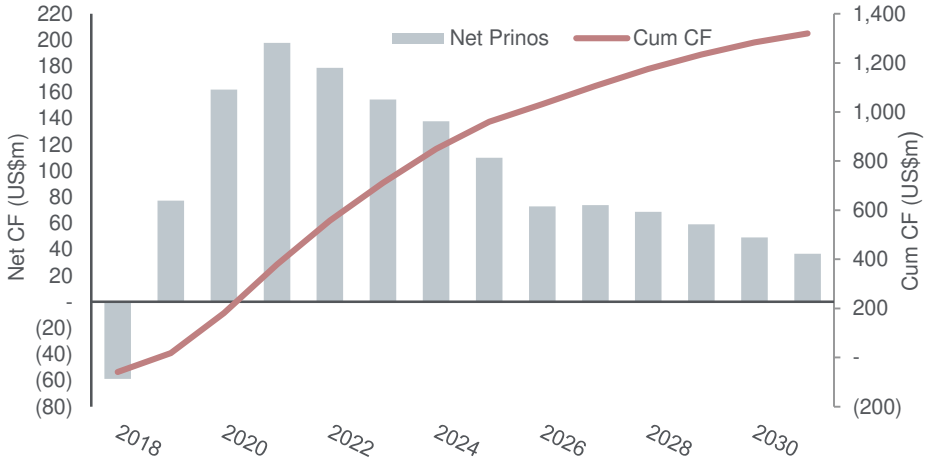
Prinos Production Profile



Prinos Existing Infrastructure

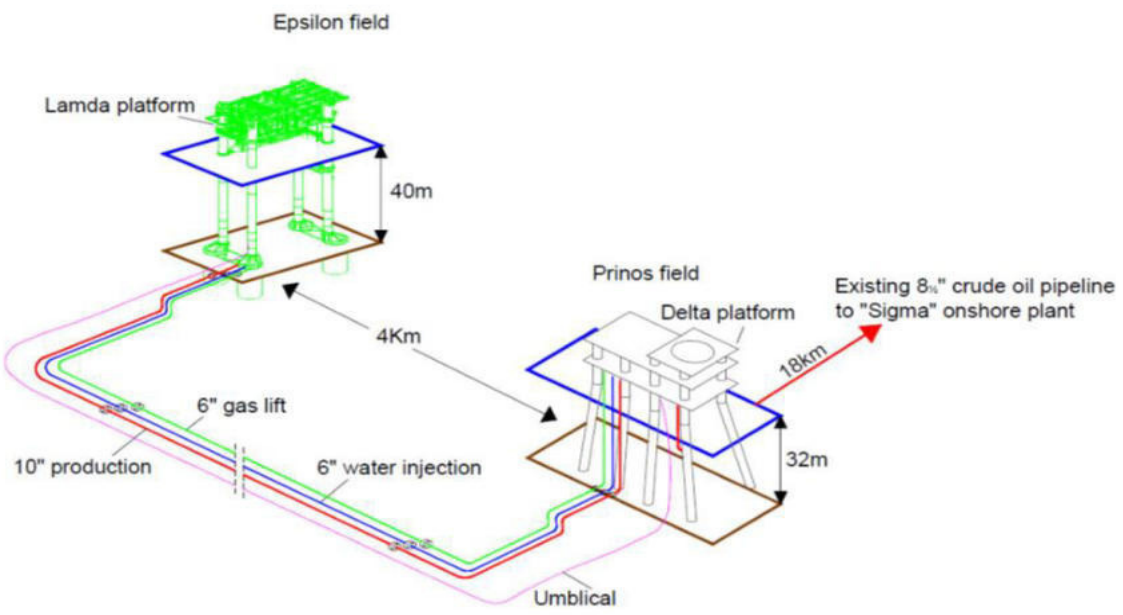


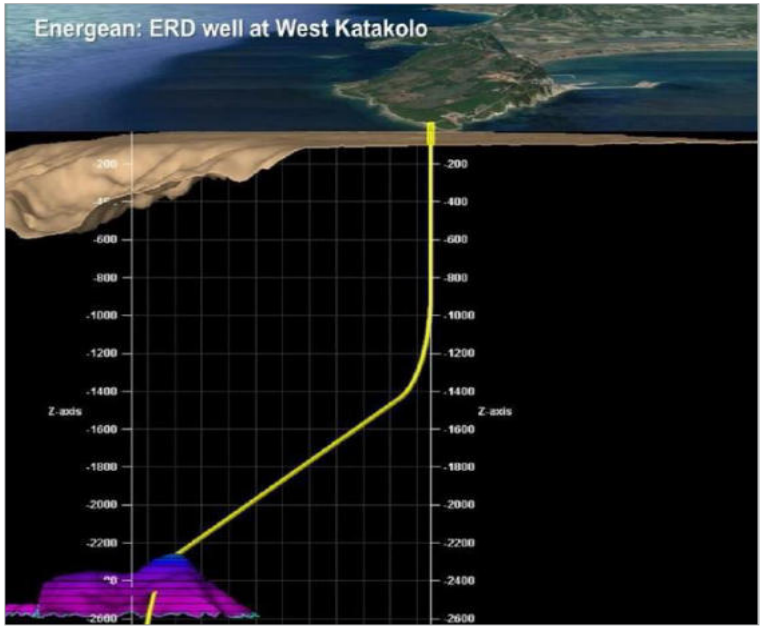
Unlevered FCF



Source: Company

Epsilon & Katakolo Development Projects, Greece, 100% WI





Epsilon Overview

- 2P reserves of 18.4 mmbbls
- Discovered in 2001
- Appraised 2010 via ERD well drilled from Prinos
- Similar reservoir setting to Prinos
- Project development through EPCIC contract with GSP, 3 production wells and a production platform Lamda
- US$155m development capex
- First oil expected 2019

Summary Fiscal Terms

Development Period	25 years staring in 2004
Royalty	2 - 10%
Corporate Tax	25%

Katakolo Overview

- 2P reserves of 10.5 mmbbls
- West Katakolo reservoir is believed to be a dual porosity system (matrix, fractures and vugs), with an overlaying gas cap and an underlying aquifer
- 2 wells tested; plan is to drill the first pilot hole to be converted to an injection well in 2019
- Commencing environmental and social impact assessment to be submitted in 2018. Company intends to take FID upon approval
- US$60m estimated development capex
- First oil expected in 2020

Summary Fiscal Terms

Development Period	25 years starting in 2016
Royalty	2 - 20%
Corporate Tax	25%

Source: Company, Katakolo NSAI CPR

Karish & Tanin – A Transformational Project in Israel (70% WI)

Key Highlights

World Class Assets

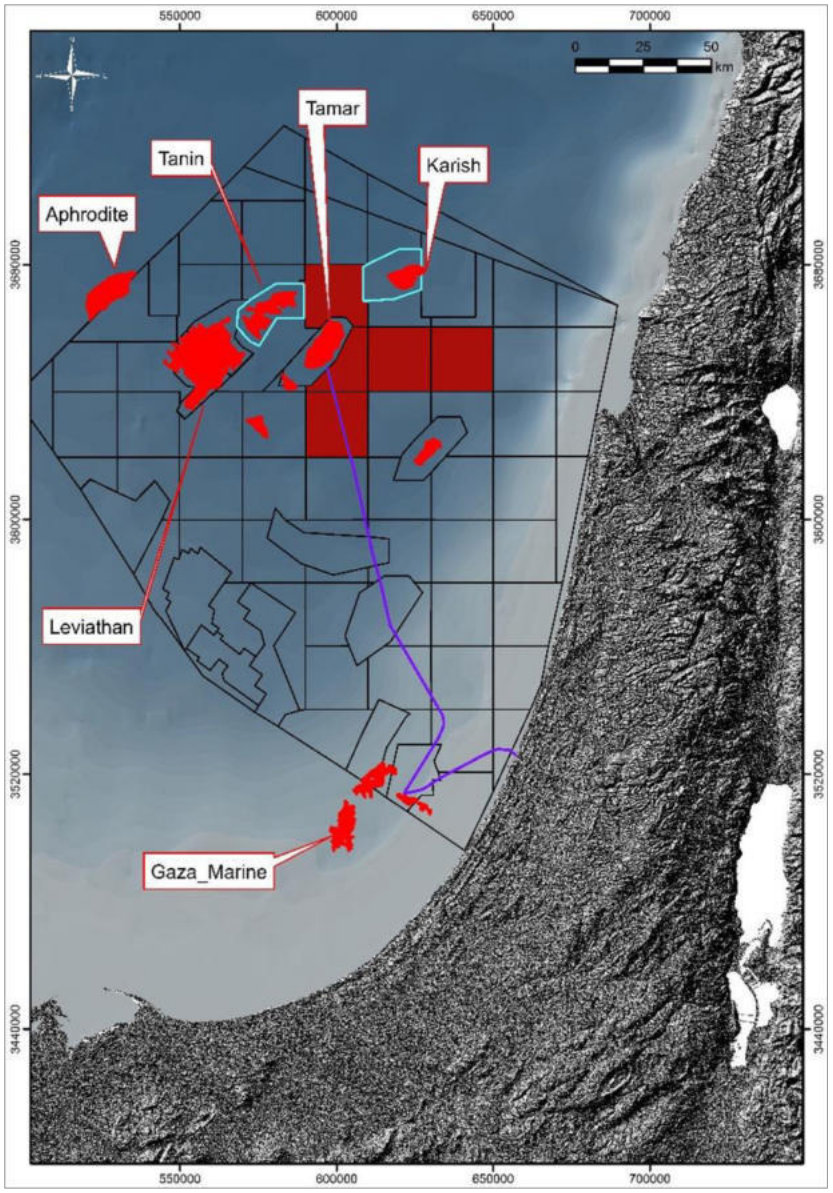
- Approximately 2.4 Tcf (67 bcm) gas
- 32.8 mmbbls hydrocarbon liquids(1)
- 8 bcm/y new build FPSO
- Part of the prolific Early Miocene Tamar Sands play with water depths exceeding 1,700 metres

Substantially De-risked Project

Regulatory	FDP approved August 2017	✓
EPCIC Contract	Lump sum turnkey EPCIC – TechnipFMC	✓
Drilling	4 firm, 6 optional wells – Stena Drilling	✓
GSPAs	4.2 bcm/yr (16yr av) $12bn revenue	✓
Project Financing	$1.275bn – Morgan Stanley, bank hapoalim, NATIXIS, SOCIETE GENERALE	✓
Equity	$460 million raise through Premium LSE IPO – Fully funded project	✓
FID	Taken March 2018	✓

Future growth

- c. 4 bcm/y capacity available
- Only floater in the East Med



Source: NSAI CPR, Company.

Karish & Tanin – Development Plan

Key Contract Terms

- **TechnipFMC $1.36 bn EPCIC Contract**
  - Two train new-build FPSO with an 8 bcm/yr capacity
  - Lump-sum turnkey EPCIC contract – timing and performance risks borne by Technip FMC
  - Project to be completed in Q1 2021
  - Spread moored FPSO built by SCM in Singapore
  - 800,000 bbls oil condensate storage capacity

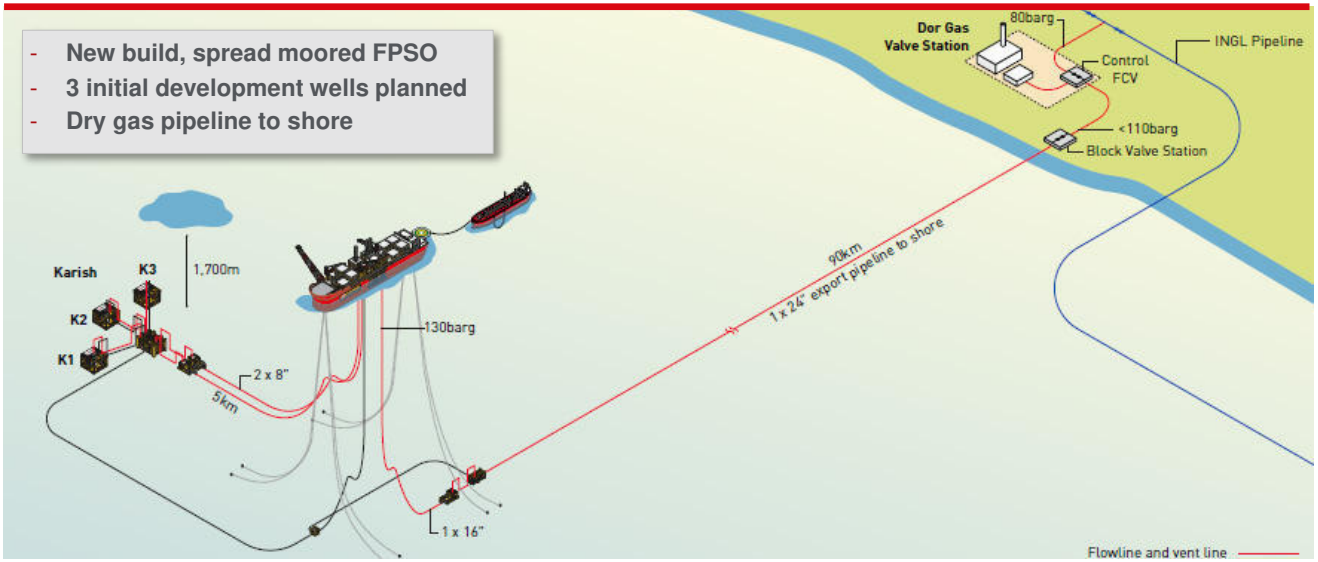
- **Stena Drilling Contract**
  - Contract in place for the development drilling of the Karish Field
  - Stena Forth drillship: Karish North & three development wells in Q1 2019
  - Energean holds option to drill 6 additional wells
- **Wood contract for O&M services**
- **Halliburton contract for Integrated Drilling Services**





Initial Development Phase

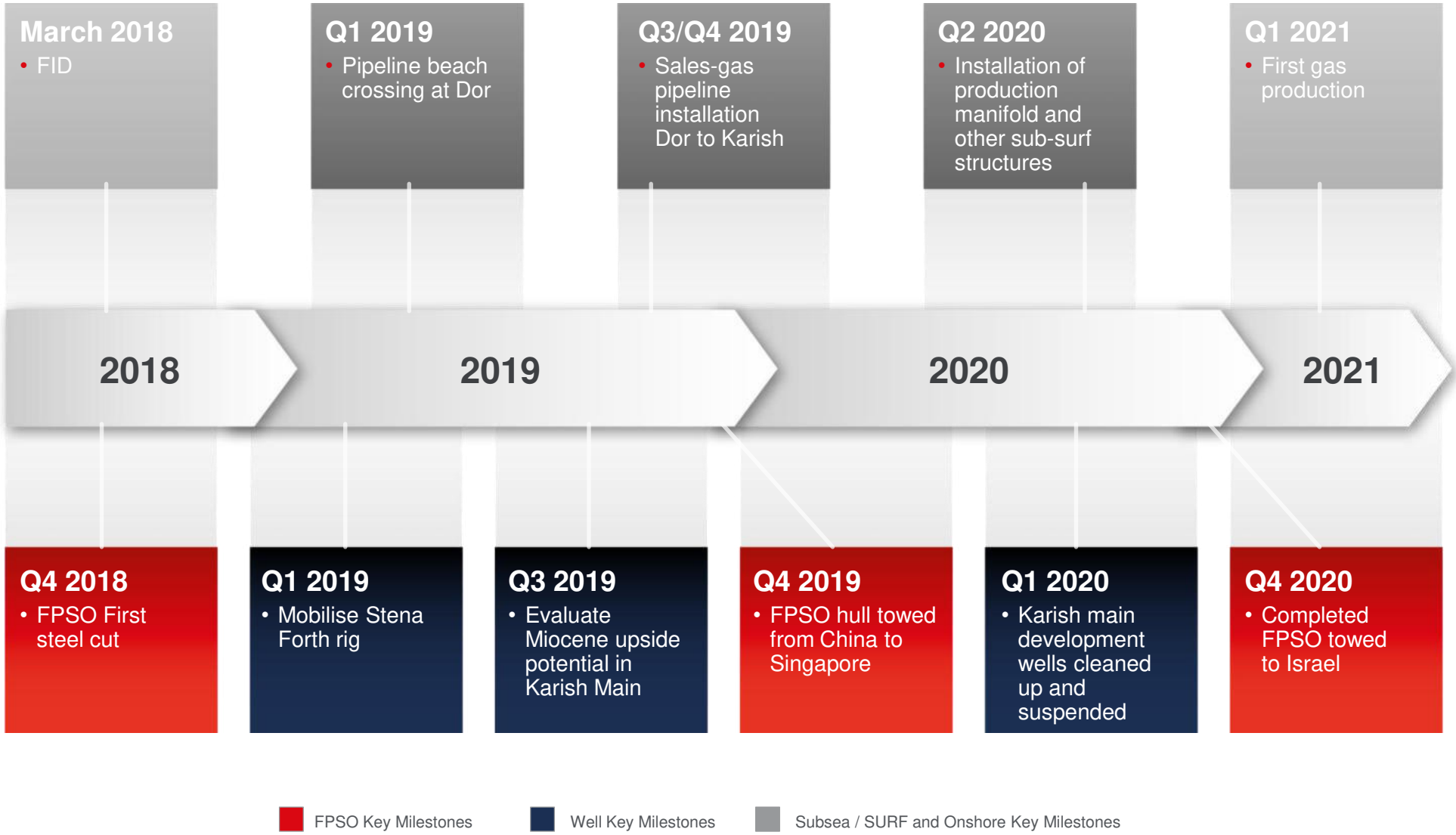
- New build, spread moored FPSO
- 3 initial development wells planned
- Dry gas pipeline to shore



Karish & Tanin – 4.2 BCM/Y GSPAs Executed

Volume	1.2 bcm/yr	2.6 bcm/yr	0.3 bcm/yr	0.1 bcm/yr
Tenor	Min: 7 years -- Weighted Average: 16 years -- Max: 20 years			
Weighted Avg Take-or-Pay	75%			
Weighted Avg Current Price	$4.1 / mmbtu			
Weighted Avg Floor Price	> $4 / mmbtu			

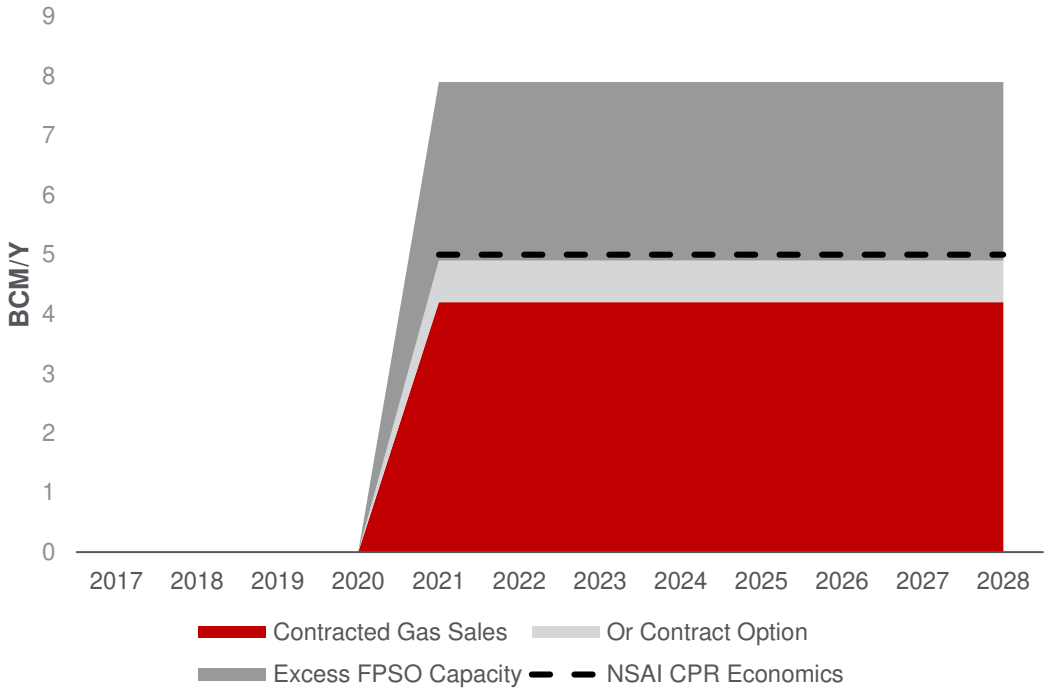
Key Milestones to Karish and Tanin First Gas



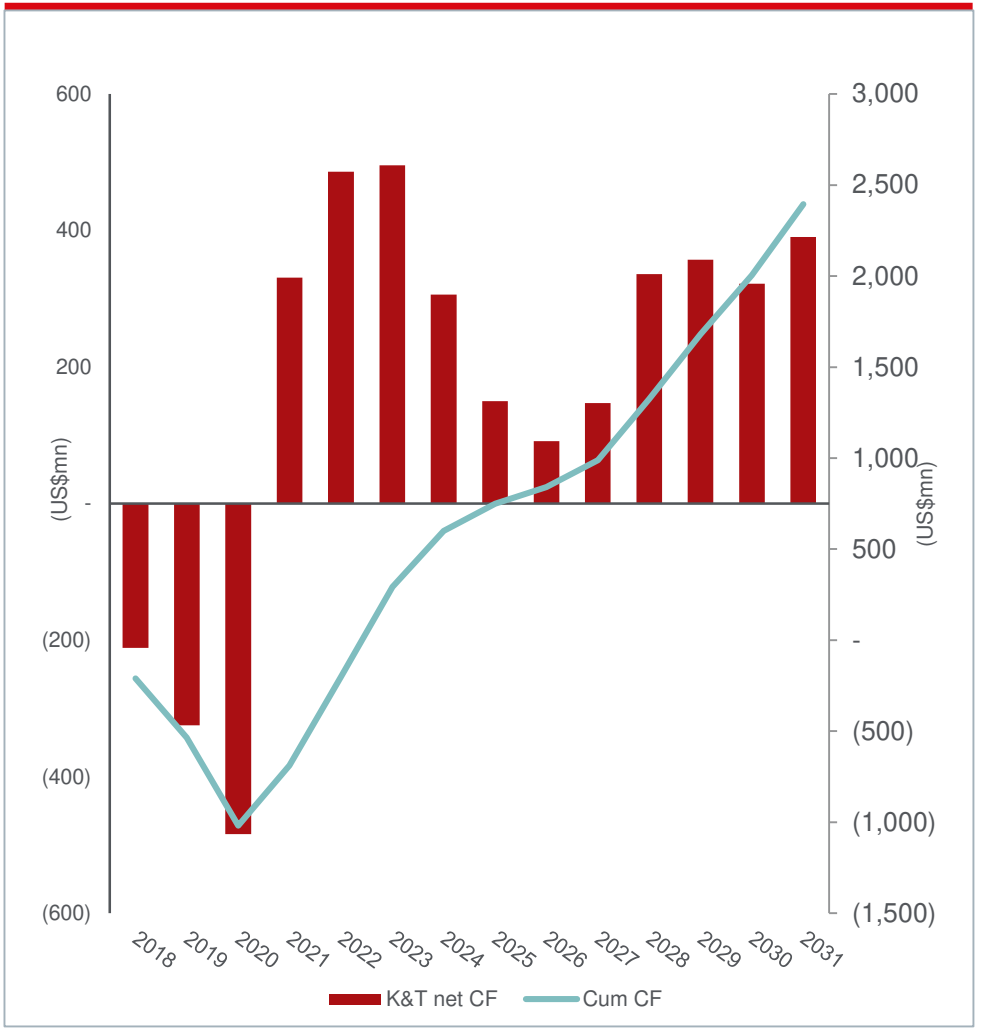
Source: Company

Karish and Tanin Operational Overview – CPR Case

Karish Tanin Contracted Gas Volumes(1)



Net Free Cash Flow Profile(2)



Source: NSAI CPR. Note: (1) NSAI figures used are gross (100%), (2) NSAI figures shown are net to 70% stake.

Israeli Gas Demand Expected to Grow

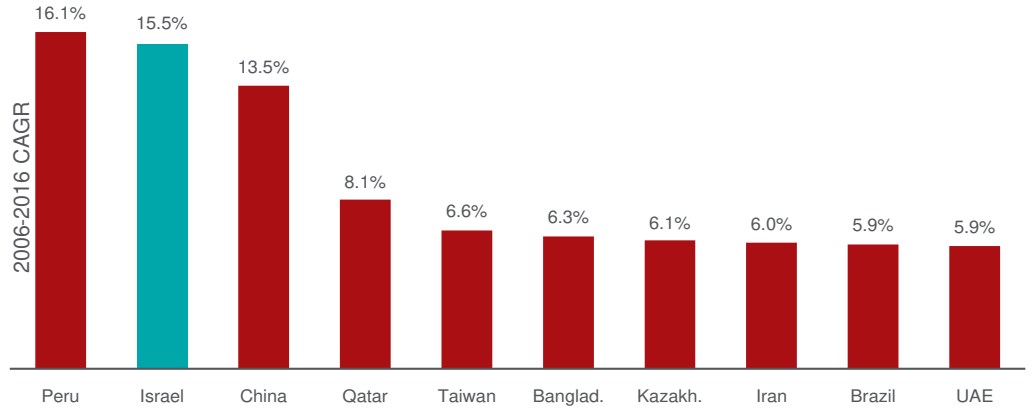
Key Highlights

- Over the last decade Israel natural gas demand has been amongst the fastest growing globally
- Y-o-y growth of 7.4% in 2017
- Future demand is forecasted to increase substantially primarily driven by electricity sector

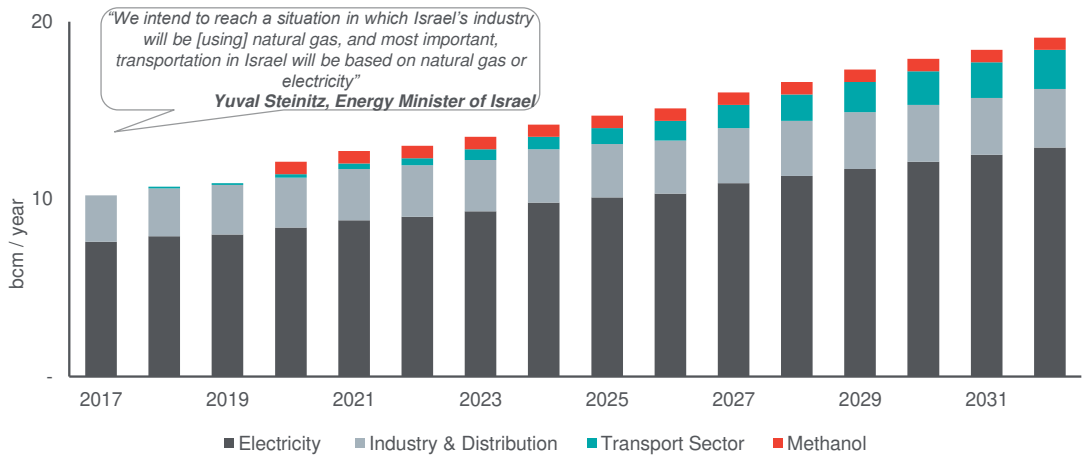
Israeli Regulatory Support

- Israeli Electric Corporation required to reduce coal generation post 2017
- August 2016 decision to close the 1,440 MW Orot Rabin coal-fired plant by June 2022 and replace it with gas-fired generation
- Incentivise light industrial customers to switch from oil to gas
- Incentivise CNG stations and electric vehicles
- Government funded deployment of a new natural gas distribution system
- 5 IEC power plants to be privatised in coming years without associated gas supply contracts

Gas Demand Increase 2006-2016 CAGR – Top 10 Countries Globally



Israeli Natural Gas Demand by Sector



Source: Israeli Electric Corporation; Israeli Ministry of Energy; BP Statistical Review of World Energy June 2017.

Near Term Exploration Upside

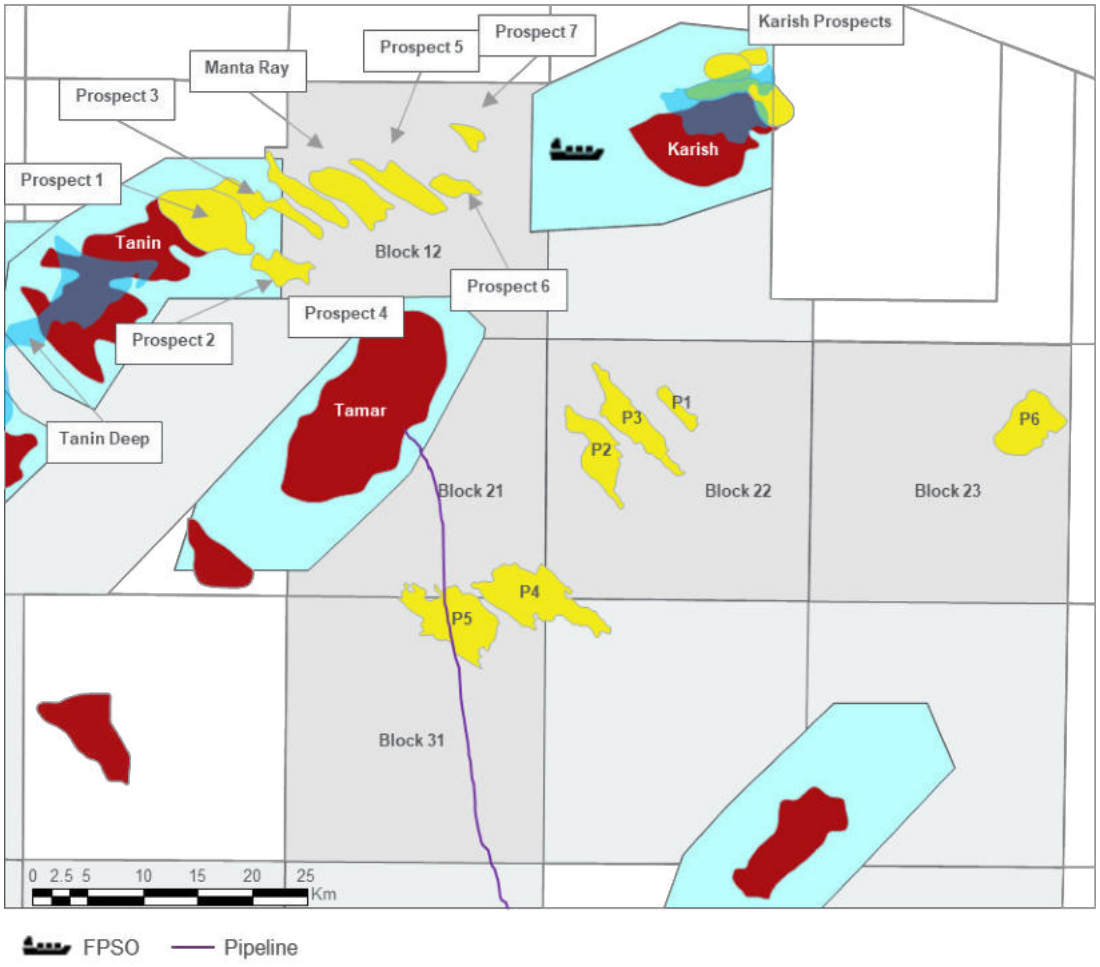
Israel Bid Round: December 2017

- Low commitments expected to be ~$6.5mn over the next three years

Karish & Tanin Unrisked Prospective Resources[1] & Exploration Blocks Recoverable Prospective Resources[2]

	Liquids	Gas	Pg[3]
	(mmbbl)	*(Tcf)*	*(%)*
Karish[1]	53	1.4	72
Tanin[1]	28	0.31	56
Block 12	5	1.15	76
Block 22	1.9	0.62	45
Blocks 21/22/31	2.1	0.71	45
Block 21/31	4.9	1.64	45
Block 23	2.5	0.82	45
Total	97.4	6.65	

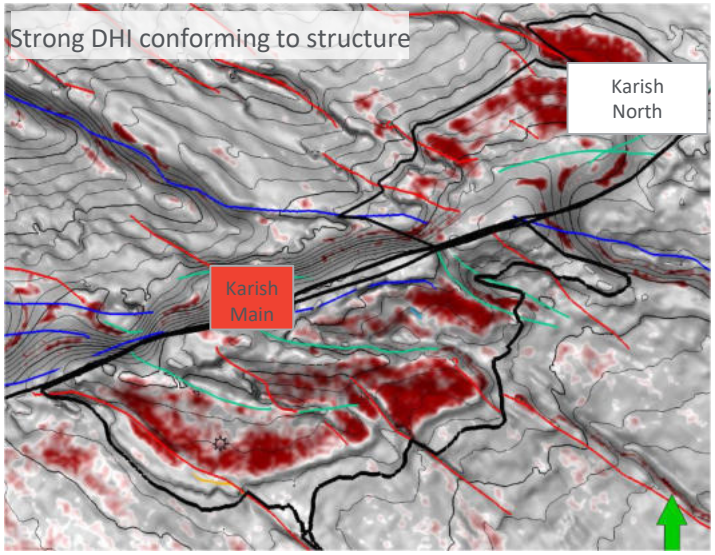
Overview of Exploration Block Locations

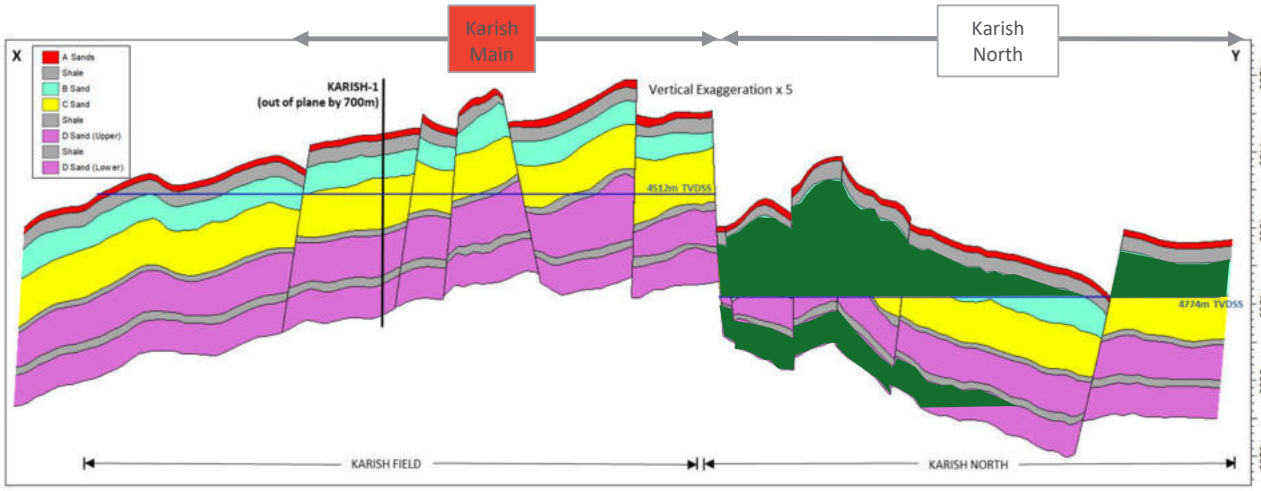


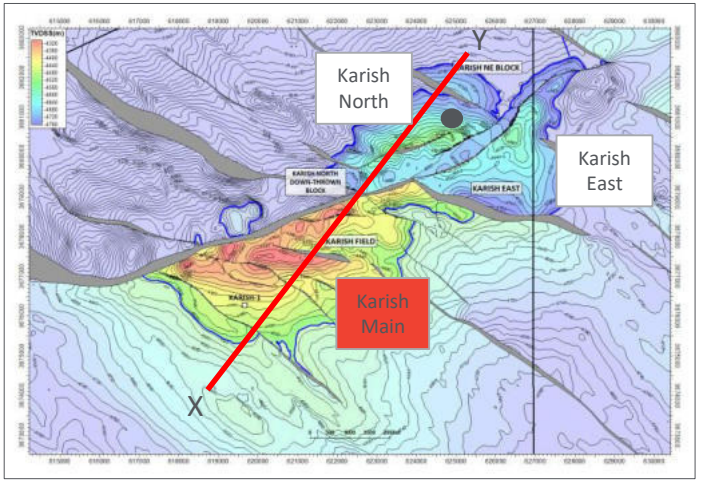
Source Company Note (1) 70% WI, based on NSAI CPR, (2) Based on NSAI CPR & Company estimates, (3) Geological probability of success

Karish North: Overview

- 3-way dip structure on the northern down-thrown side of the Karish Main bounding-fault
- High Probability of Success of finding gas in B, C and D sands (e.g. 81% POS: C sands –NSAI CPR)
- Calculated GIIP = 1.84 Tcf, based on predicted GWC and Karish Main properties. Unrisked recoverable resources = 1.20 Tcf from a single well. Karish North fluids may contain more liquids than Karish Main
- Well to be drilled immediately prior to Karish Main 3-well development drilling campaign. Spud before end March 2019. Expected cost ~ US$15 to $25mn
- Discovery well would be tied back to the FPSO via an insulated 5km flowline with volumes being rapidly monetised through the pre-installed excess FPSO capacity 4 bcm/y

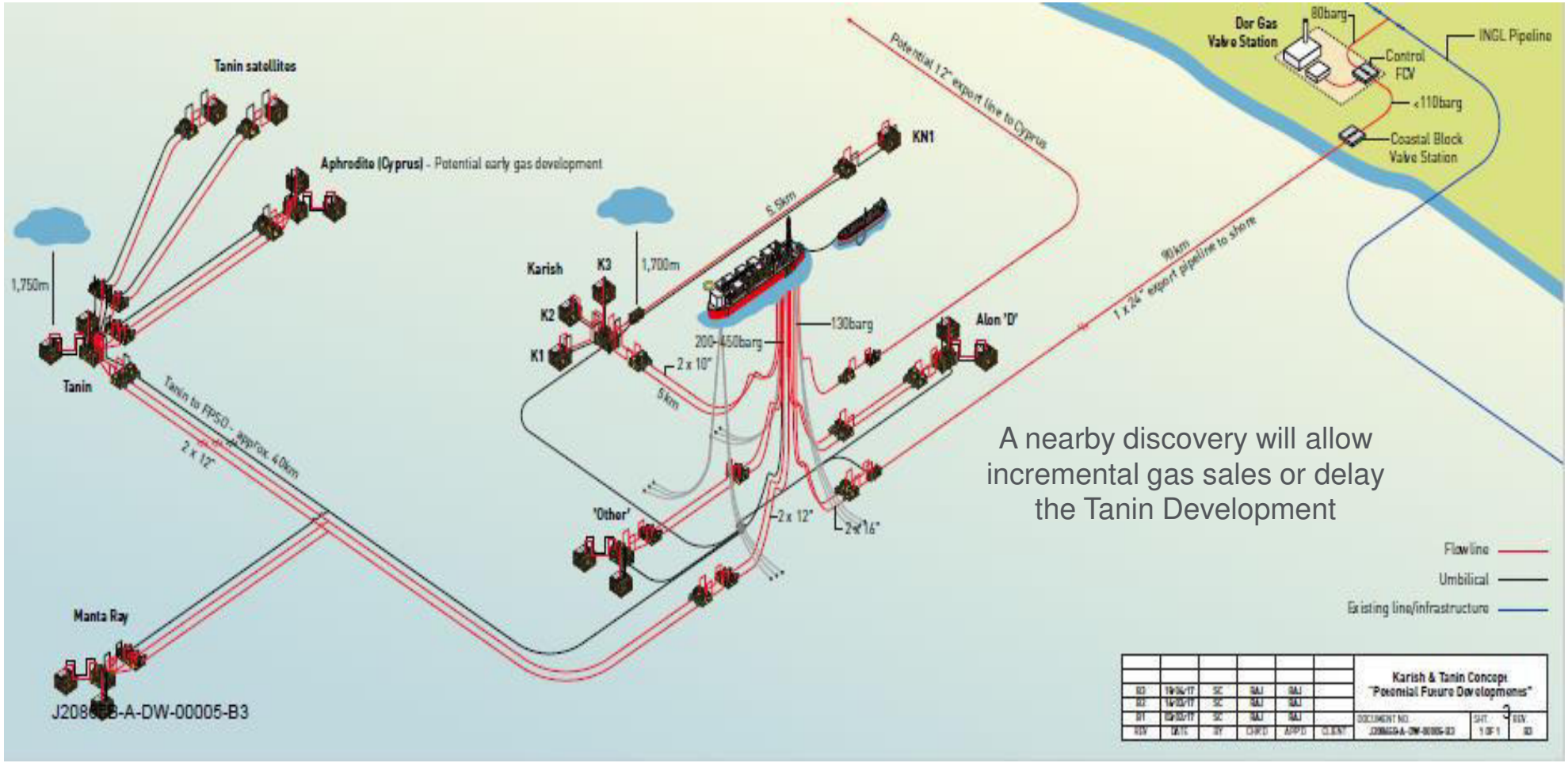






Karish & Tanin FPSO – A Hub to Commercialise Other Fields

Overview of Karish & Tanin FPSO Potential Tie-Ins



Source: Company

Exploration Upside in Western Greece and Montenegro

Western Greece JV with Repsol

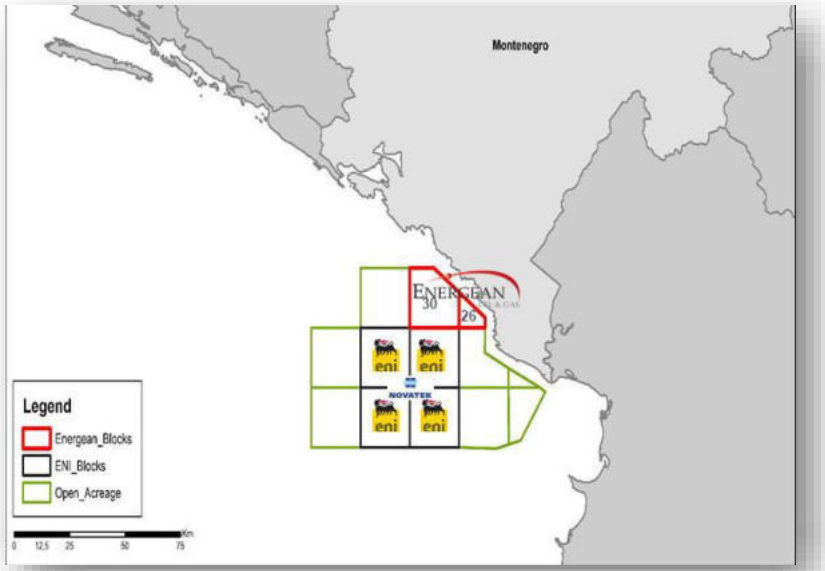
- Repsol 60% partner and operator
- First exploration phase run through 2019 for Ioannina and 2021 for Aitoloakarnania
  - 205 mmboe gross unrisked prospective resources
  - Repsol has started seismic exploration activities
  - €15.1m commitment
- Two year optional second exploration period:
  - Total commitment of approximately €23m
  - Decision to enter next exploration phase expected in Oct 2019 (only Ioannina)



Source: Company

Montenegro Key Highlights

- Blocks 4218-30 and 4219-26 officially awarded in March 2017 (Energean 100%)
- NSAI audited 1.8 Tcf of unrisked prospective resources of gas plus 144 mmbls of hydrocarbon liquids
- First exploration phase: low commitment
  - Mandatory work program: 3D seismic acquisition covering two blocks + G&G studies + training
  - 100% cost c. $5m
- Four year optional second exploration period:
  - 1 firm exploration well of not less than 2,800 m
- ENI operates 4 blocks to the south



Future Catalysts: Active Work Programme

Production



- Complete 25 well development programme at Prinos
- Epsilon field onstream

Target 2021 production > 10 kbopd

Development



- Drill 3 wells in Karish
- 4.2 bcm/y forward sold under firm contracts
- Potential to sign additional GSPAs
- 2021 first gas
- Katakolo FID – a $100 million NPV project

Deliver stable, long-term cash flow

Exploration



- Karish North well committed to end of March 2019
- 3D and G&G work programme over 5 Israeli Blocks
- 6 options to drill exploration wells contracted with Stena
- 2D seismic survey – W. Greece, targeting 205 mmboe un-risked prospective resources, (40% WI)
- 3D seismic survey - offshore Montenegro, targeting 438 mmboe un-risked prospective resources, (100%WI)

Active three country exploration programme

Strengthen and Grow the Eastern Mediterranean E&P champion

Appendix

12 Month Outlook

(1) Five development wells, Prinos Basin



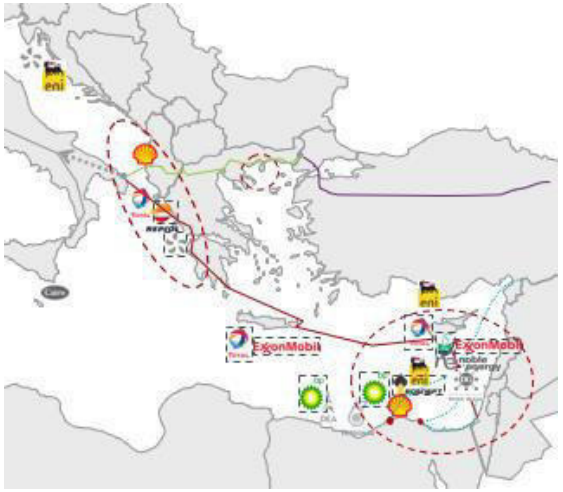
(2) Karish & Tanin project delivery



(3) Karish North Exploration Drilling



(4) Business Development Opportunities



Energean Board of Directors

Non Executive Directors



Simon Heale – ***Independent Non-Executive Chairman***

- Currently serves as Chairman of Gulf Marine Services, Marex Spectron and Kaz Minerals
- Prior to this served as NED and Chairman of Panmure Gordon, and as NED of PZ Cussons, Morgan Advanced Materials, Coats and Carlton Commodities



Stathis Topouzoglou – ***Non-Executive Director***

- Shipowner with more than 35 years' experience in the energy transportation sector
- Founding partner of Energean Oil & Gas
- Principal shareholder and founder of Prime which has more than 35 vessels under management



Ohad Marani – ***Independent Non-Executive Director***

- Board Member of Bank Leumi of Israel and member of the Investment Committee of Israel's Infrastructure Fund
- Previously Chairman of the board of Emmanuelle Energy, Israel Natural gas Lines and Alumot Investment House
- Served as Director-General of Israel Finance Ministry and also in the Israeli Embassy in Washington



Andrew Bartlett – ***Senior Independent Director***

- Started his career in Royal Dutch Shell where he worked for 21 years
- 11 years of investment banking experience and former Global Head of Oil & Gas M&A and Project Finance at Standard Chartered
- Advisor to Helios Investments and NED of Africa Oil and Impact Oil & Gas
- Served as Chairman of Azonto Energy and a NED of Eland Oil & Gas



David Bonanno – ***Non-Executive Director***

- Third Point representative to the Board
- Primary investment professional responsible for all Third Point's activities in Greece
- Previously worked at Cerberus and Rothschild



Robert William Peck – ***Independent Non-Executive Director***

- Ambassador Peck has almost 35 years in the Government of Canada as a career Foreign Service Officer
- Resident mentor in the Human Resources Bureau at Global Affairs Canada
- Has held diplomatic roles in Nigeria, Switzerland, Algeria and Greece



Karen Simon – ***Independent Non-Executive Director***

- Vice Chairman in Investment Banking with over 30 years of banking experience with JP Morgan
- Currently heads up Director Advisory Services. Also sits on the Board of Aker ASA in Norway and Youth Inc., a New York City charity serving under privileged youths.
- Awarded "Most Influential Woman in Private Equity Advisory" by Private Equity News in 2010 and in 2011 and was cited several times as one of the 100 Most Influential Women in Europe, Middle East and Africa by Financial News.

Executive Directors



Mathios Rigas

Chief Executive Officer

- Founding Shareholder
- Petroleum engineer with 20 years of investment banking and private equity experience mainly in the oil & gas sector



Panos Benos

Chief Financial Officer

- Chartered accountant with more than 15 years oil & gas experience both in banking & industry
- Joined Energean from Standard Chartered Bank.

Energean Management Team

Senior Management



Dr. Stephen Moore – *Chief Growth Officer*

- 28 years of E&P experience at Shell, Maersk Oil and Mubadala
- Previously Senior Vice President – Technical at Mubadala



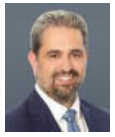
Vassilis Tsetoglou- *Group HSE Manager*

- Electrical Engineer with 15 year of experience on HSE Management in high H2S environments Worked for Kavala Oil and Eurotech Services



Vincent Reboul-Salze – *EPCiC Project Director*

- 14 years of industry experience
- Previously Lead Process Engineer for Shell / Gap KCO



Dennis Anestoudis – ***Exploration Manager***

- Geophysicist with more than 20 years of experience
- Team Leader Africa, Genel Energy
- Previously work for Schlumberger and Hellenic Petroleum



Michelle Churchward-*Group General Counsel*

- Legal Manager in Sterling Energy, worked in OMV, Schlumberger, BG Group
- Worked in E&P projects in the Falkland Islands, Morocco and Egypt



David Donaldson – *Managing Director Prinos Asset*

- • Petroleum Engineer with over 30 years of industry experience
- • Held senior drilling engineer positions at Shell, Eni and Halliburton



Fred Riddiford – *Reservoir Engineering Manager*

- Reservoir Engineering with almost 40 years of experience
- Previously VP Reservoir Engineering at Mubadala



Yaron Daissy – *Karish Onshore Delivery Manager & Head Regulatory Compliance*

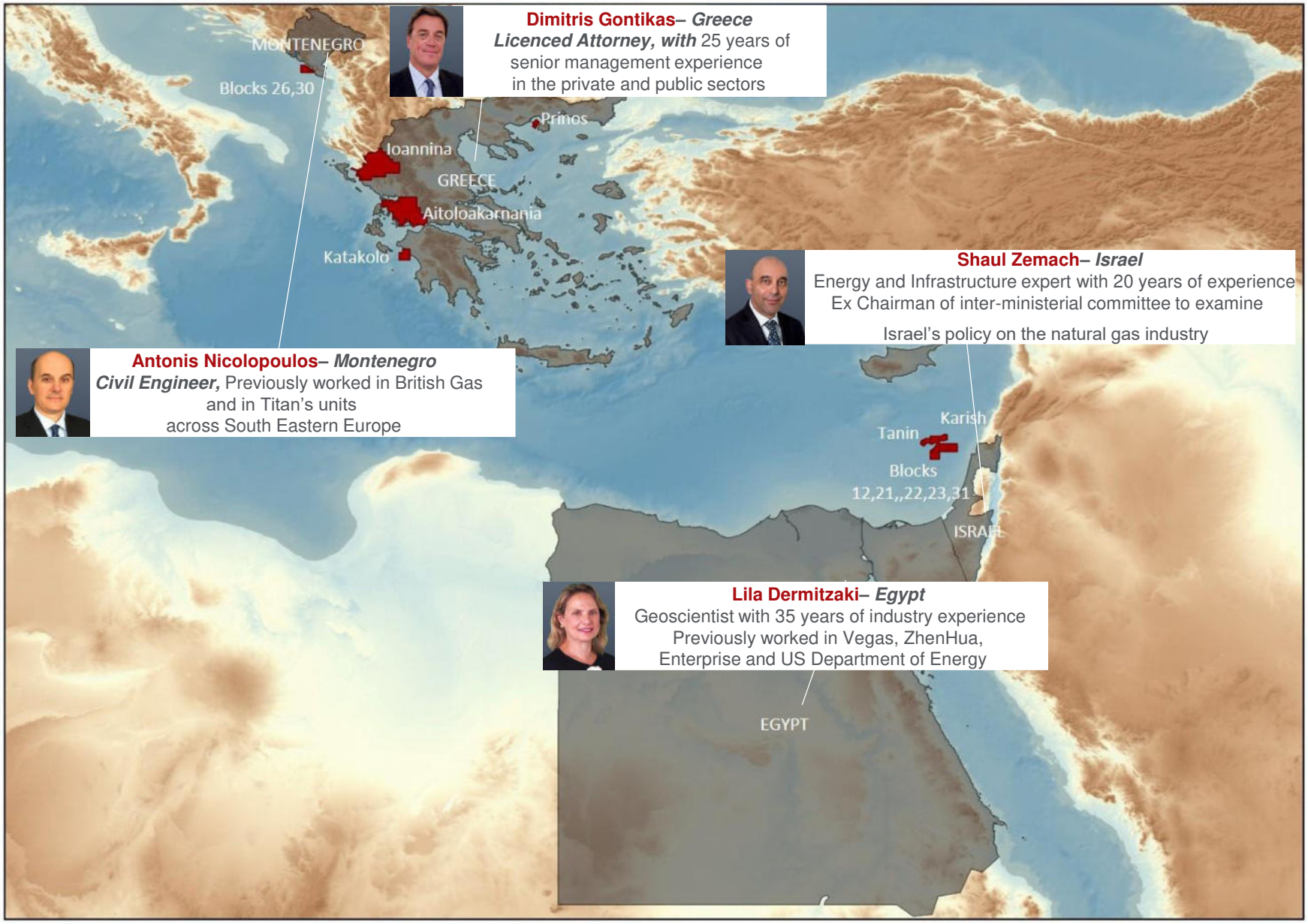
- Mechanical Engineer, 20 years in oil & gas
- Worked 15 years at Noble Energy in the Tamar and Leviathan projects



Kate Sloan-*Head of Investor Relations*

- Senior Equity Analyst-Oil & Gas Macquarie Group for 4 years
- Oil & Gas Equity Analyst in Liberum and Daniel Stewart, also worked in Braemar Seascope, Deloitte LLP, Booz Allen

Country Managers



Dimitris Gontikas– *Greece*
Licenced Attorney, with 25 years of senior management experience in the private and public sectors

Shaul Zemach– *Israel*
Energy and Infrastructure expert with 20 years of experience
Ex Chairman of inter-ministerial committee to examine Israel's policy on the natural gas industry

Antonis Nicolopoulos– *Montenegro*
Civil Engineer, Previously worked in British Gas and in Titan's units across South Eastern Europe

Lila Dermitzaki– *Egypt*
Geoscientist with 35 years of industry experience
Previously worked in Vegas, ZhenHua, Enterprise and US Department of Energy

Historical Financial Results Highlights

Financial Highlights			
$ mn, unless otherwise stated	2015	2016	2017
Realised Sales Price ($/bbl)	44	34	46.7
Production (boepd) [1]	1,459	3,490	2,803
Revenues	28.4	39.7	57.8
Adjusted EBITDAX[2]	(1.2)	16.2	20.7
Cost of Production	(21.7)	(24.3)	(25.3)
Cash Flow from operating activities	(2.8)	15.2	29.1
Capital Expenditure [3]	(49.2)	(110.7)	(70.3)

Notes: (1) Only oil production volumes shown as gas produced at the Prinos basin is not sold. (2) Adjusted EBITDAX is calculated as profit or loss for the period adjusted for profit or (loss) for the period from discontinued operations, taxation (expense) / income, total depreciation, amortisation of intangible assets, other income, other expenses, finance income, finance costs, gain on derivative, net foreign exchange (loss) / gain and exploration and evaluation expenses. (3) Capex includes cash purchases of PP& and intangible assets.

Excellent HSE Record in sensitive areas

+30% increase in arrivals at “Megas Alexandros” airport and 1,5 million visitors in Thasos in 2017





Energean’s HSE Mission

To transfer our 37 years’ experience of working safely in NE Greece’s environmentally sensitive locations to every area we operate in

European Commission

Safety of Offshore Oil & Gas Operations Directive

Creating a safe and healthy working environment

Over 10 red-flag beaches every year in the Gulf of Kavala






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2018 HALF YEAR RESULTS

Wednesday 12 September 2018

Disclaimer

This presentation may contain forward-looking statements and information that both represents management's current expectations and beliefs and are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business and with any statement about the future.

Whilst Energean believes that such expectations and beliefs are reasonable in the light of the information available at this time, the actual outcomes may be materially different from the said statements, owing to factors beyond Energean's knowledge or control (or within Energean's control where, for example, the Company decides on a change in strategy).

Energean undertakes no obligation whatsoever to revise any such forward looking statements to reflect any changes (in expectations, beliefs, circumstances, events, the Group's plans or strategy or otherwise). Accordingly, no reliance may be placed on such forward looking statements or any figures therein.

2018 Half Year Results Summary & Outlook

Operational Highlights

- Raised $460 million through Premium London Stock Exchange IPO
- Arranged $1,275 million of project financing for Karish-Tanin
- Signed lump-sum EPCIC with Technip
- Took Final Investment Decision for Karish-Tanin in March 2018
- Increased[1] net 2P reserves to 349 mmboe from 51 mmboe at the point of Listing
- Identified 7.5 Tcf of gross prospective resources offshore Israel with a high geological probability of success
- Committed to the high impact Karish North exploration well, commencing February 2019 and targeting 1.3 Tcf of gross recoverable prospective resource (Energean 70%)
- Drilled an Extended Reach Horizontal well into Prinos North; well contributed > 1,000 bopd in 1H 2018
- No environmental incidents occurred during 1H 2018; all environmental KPIs within expected range

2H 2018 Operational Outlook

- First steel cut on Karish FPSO Hull
- Complete planning for Karish North exploration well
- Production will continue to grow at Prinos
  - Early production from the Epsilon field from Extended Reach Well
  - Drilling of one vertical well and commencement of a second at Epsilon
- Early stage seismic operations continue in Greece and Montenegro
- Tel Aviv Stock Exchange Secondary Listing

1. Post-period end

2018 Half Year Results Summary & Outlook

Financial Highlights

Production	Production Costs
3,801 bopd	$19 /boe
1H 2017: 2,534 bopd	1H 2017: $26 /boe

Revenue[2]	EBITDAX[2]
$26 million	$17 million
1H 2017: $27 million	1H 2017: $8 million

Net cash / debt	2P Reserves[1]
$167 million	349 mmboe
FY 2017: ($76 million)	FY 2017: 51 mmboe

2018 Guidance

Production	Production Costs
Narrowed to 4,000 – 4,250 bopd	$17 – 19 /bbl

SG&A	Accrued E&A Capex
$10 million	$10 million

Accrued D&P Capex – Ex-Israel	Accrued D&P Capex –Israel[1]
$120 million	$340 million

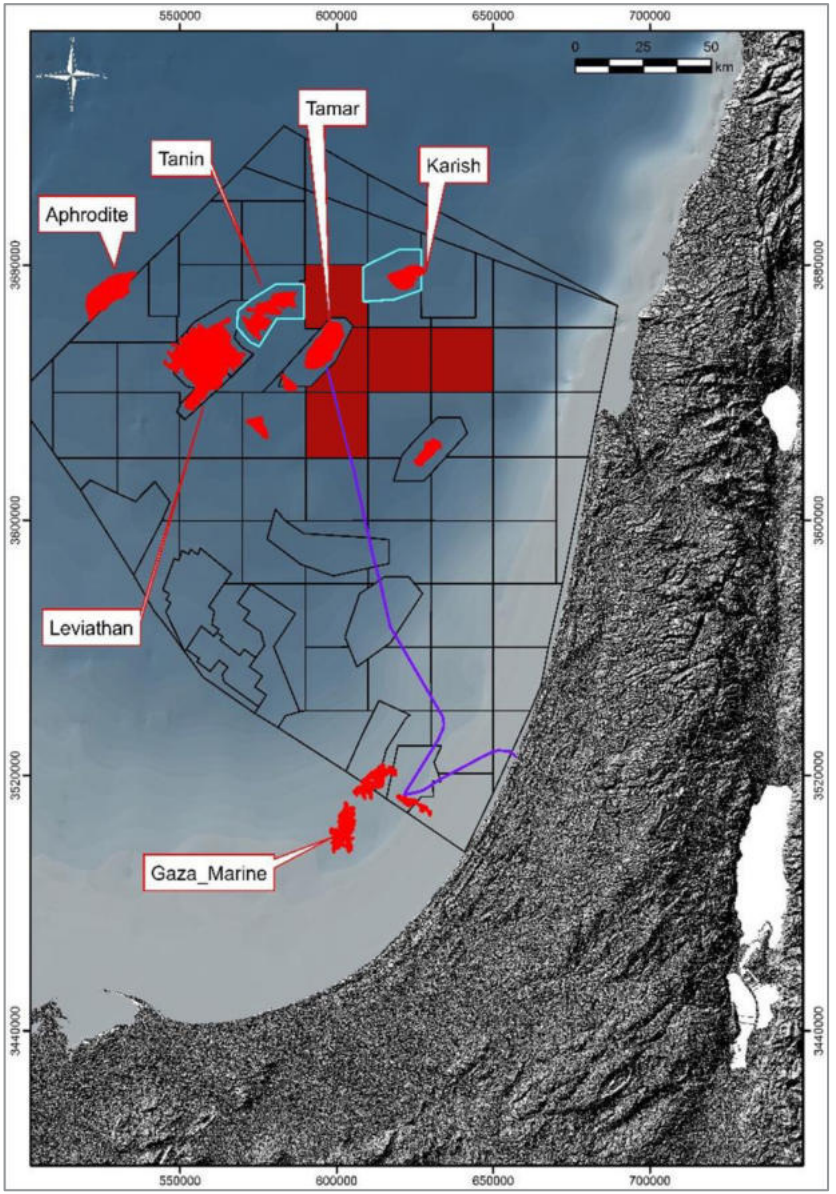
1) Post-period end
2) 1H 2018 revenue includes sale of one versus two cargoes sold in the equivalent period in 2017; increased production in the period is reflected in the increase of inventory. The sales volume impact, due to timing of cargoes in the first half of the year, is offset by higher realised pricing; in 1H 2018 Energean achieved an average sales price of $57.7/bbl (1H 2017: $43.5/bbl)

Developing reserves - a de-risked project in Israel

Risk Mitigation at Karish-Tanin

Regulatory	FDP approved August 2017	✓
EPCIC Contract	Lump sum turnkey EPCIC — TechnipFMC	✓
Drilling	4 firm, 6 optional wells — Stena Drilling	✓
GSPAs	4.2 bcm/yr (16yr av) $12bn revenue	✓
Project Financing	$1.275bn	✓
Equity	$460 million raise through Premium LSE IPO	✓
FID	Taken March 2018	✓





Developing reserves – mitigating risk through gas sales

Volume	4.2 bcm/yr
Tenor	Min: 7 years -- Weighted Average: 16 years -- Max: 20 years
Weighted Avg Take-or-Pay	75%
Weighted Avg Current Price	$4.1 / mmbtu
Weighted Avg Floor Price	> $4 / mmbtu

Dalia Power Energies

Dorad Energy operates an 870MW CCGT. Shareholders include EAPC (Israeli Ministry of Finance as trustee), Dori Energy, Edeltech and Zorlu of Turkey

EDELTECH

TASE-listed, operates the Dead Sea Works, the largest chemical company in Israel producing fertiliser products for global export

Dalia Power Energies 0perates the largest IPP in Israel, a 910MW CCGT. Privately owned. Largest shareholder (Energy Sector Ltd.) represents 270+ kibbutzim and moshavim

ICL

Edeltech is a private company that owns and operates two cogeneration stations as well as a shareholding in Dorad (above), and O&M contractor, Ezom

OPC

TASE-listed power generator, operates CCGT IPP at Rotem (380 MW) and cogeneration

BAZAN GROUP
FORMERLY ORL

Bazan formerly Oil Refineries Limited (ORL) TASE-listed, operates largest refinery in the Eastern Med at Haifa, c. 200k bbl/d. station at Hadera (148MW)

SUPERGAS

Supergas is a gas marketing company owned by the Azrieli Group, one of the largest in Israel. Sister company operates one of the franchise areas for gas distribution in northern Israel

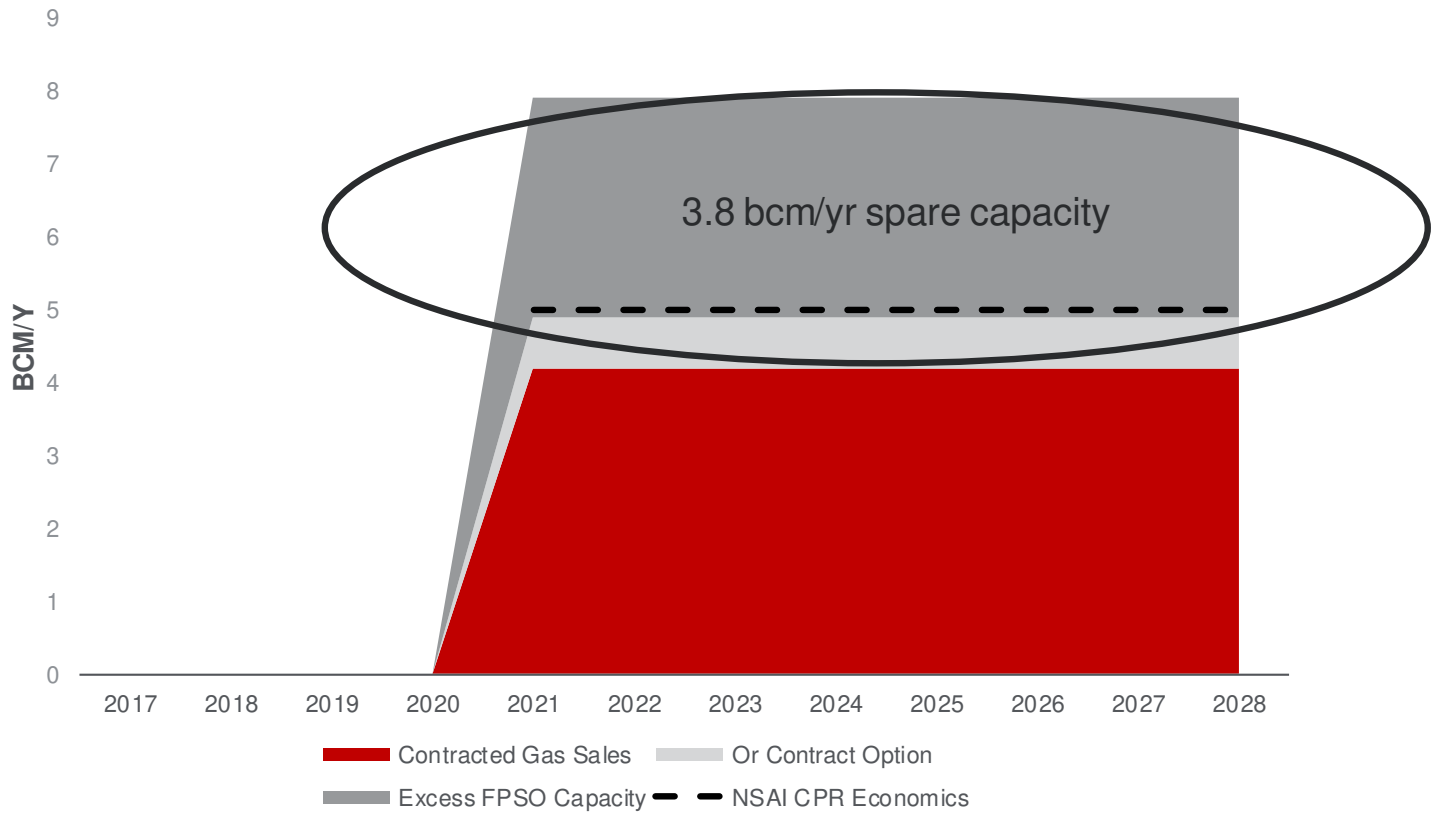
Rapac
Communication & Infrastructure Ltd.

Rapac is an engineering group involved in energy, defence, communications and aerospace. Owns two cogeneration projects at Alon Tavor and Ramat Gabriel

Adding more hydrocarbons: our infrastructure opportunity

Additional FPSO capacity

- 4.2 Bcm/yr contracted gas sales leaves 3.8 Bcm/yr of spare capacity (inclusive of the 0.7 Bcm/yr Or option)
- Sunk costs increase net cash flow margins on incremental throughput (25% to >50%)

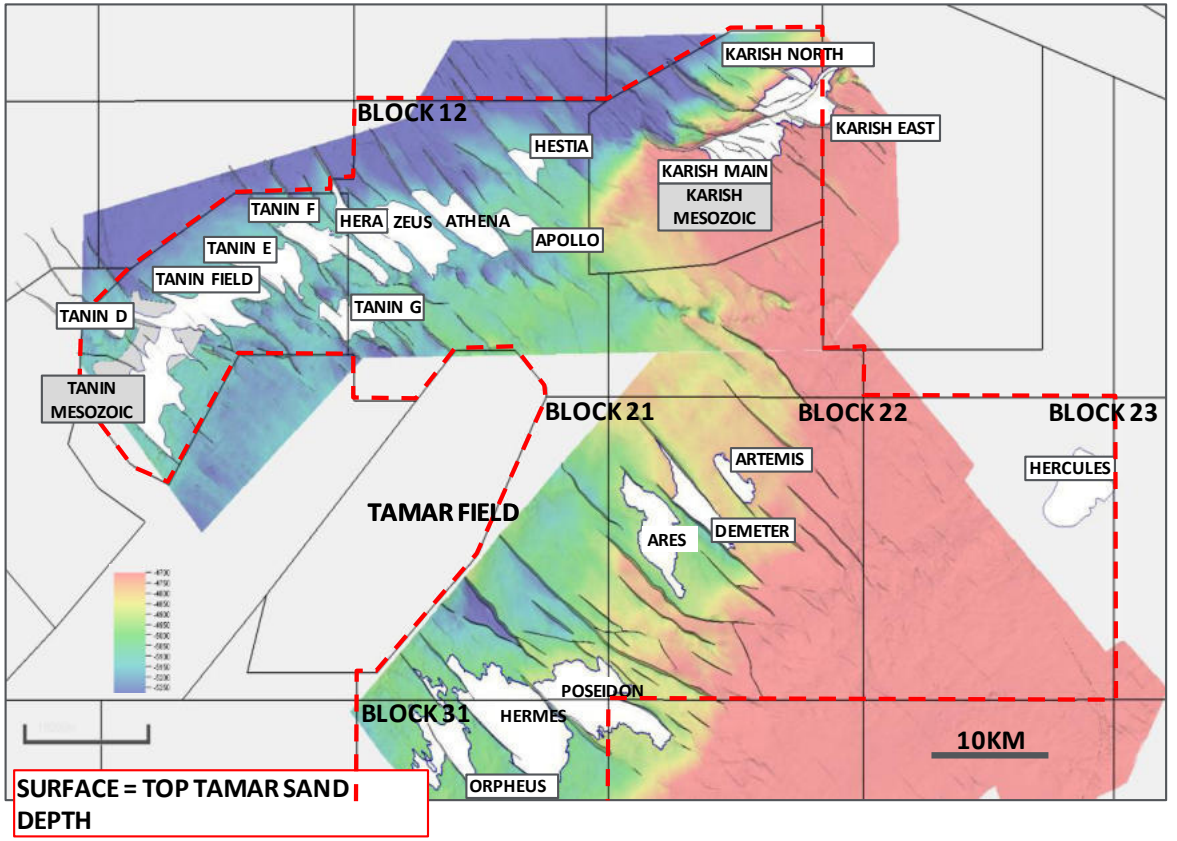


Adding more hydrocarbons - prospective resource overview

Unrisked gross prospective resource volumes

	Liquids (mmbbl)	Gas (Tcf)	Geological Chance of Success (%)
Karish	39.0	2.5	70
Tanin	40.0	0.4	74
Block 12	5.7	1.2	75
Block 22	0.5	2.5	58
Blocks 21/22/31	3.0	0.6	57
Block 21/31	6.7	1.4	57
Block 23	4.4	0.9	37
Total	101.0	7.5	

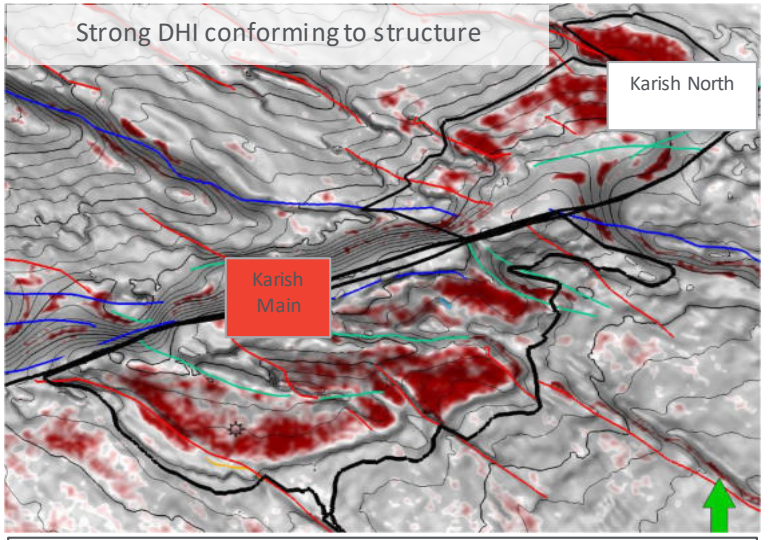
Prospect locations

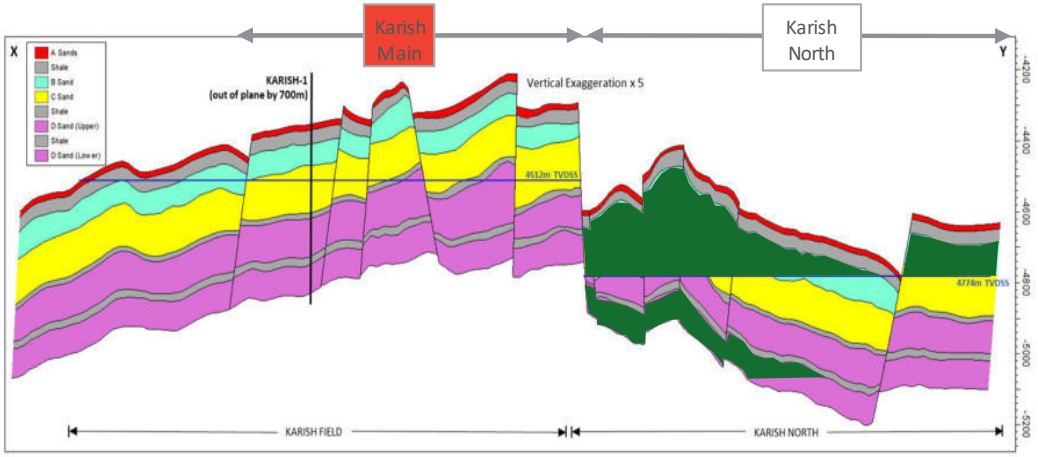


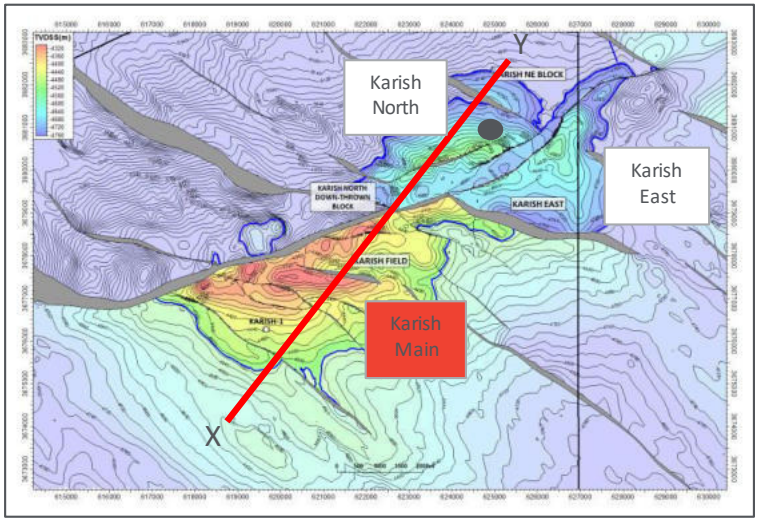
Adding more hydrocarbons - committed well at Karish North

Karish North

- Spud: March 2019. Drill time 45 days
- 1.3 Tcf + 16.4 million bbls gross recoverable prospective resources (Energean 70%)
- High Geological Chance of Success – 69% volume weighted average[1]
- Exploration well budget $25 million
- Exploration well to be suspended as potential producer
- Single well development in the success case
- 5 km tie back to the FPSO, estimated cost (including completion) $100 million
- Commercialisation: Sell more gas *or* delay Tanin development



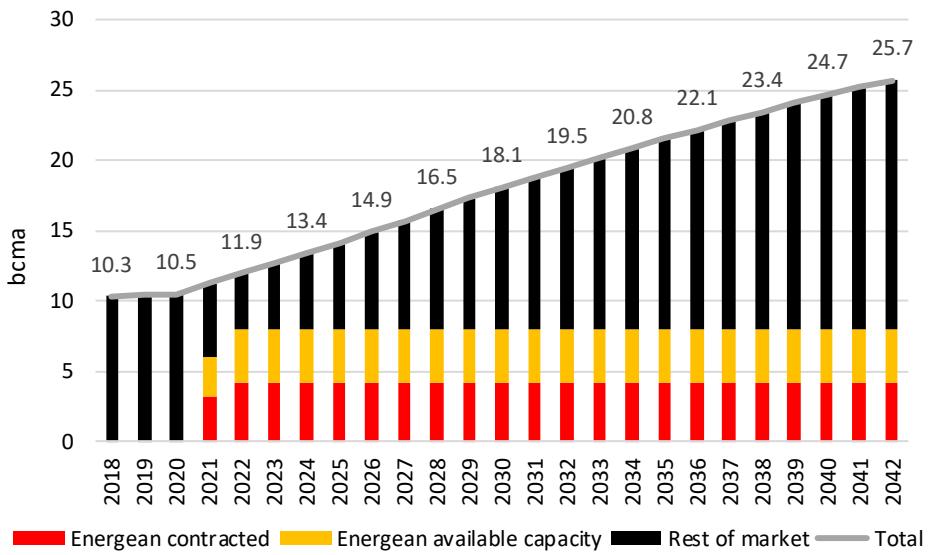




1. Previously quoted figure of >80% relates to the C sands only. C sands still have an individual chance of success > 80%

Adding more hydrocarbons – commercialisation options

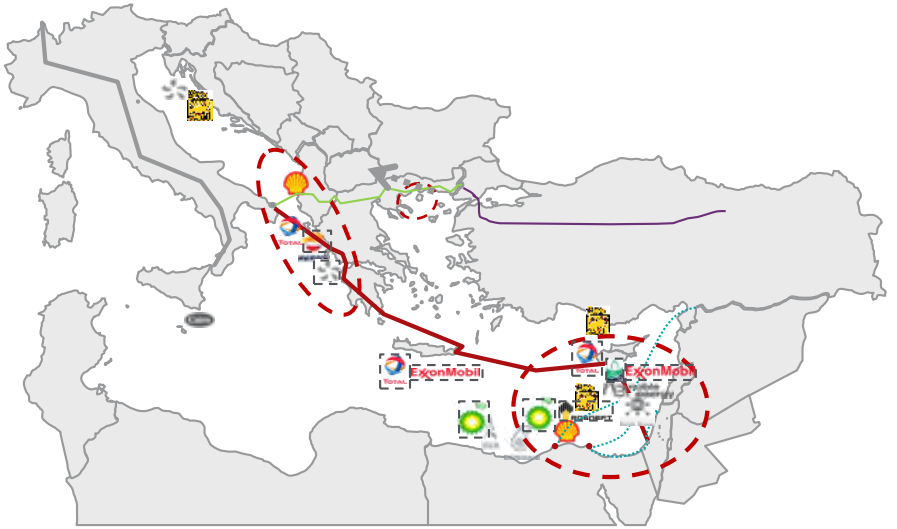
Meeting Growing Israeli Gas Demand



- A market that has grown by an average 15% CAGR for the last 10 years
- IEC required to reduce coal generation post 2017
- August 2016 decision to close the 1,440 MW Orot Rabin coal-fired plant by June 2022 and replace it with gas-fired generation
- Incentivise light industrial customers to switch from oil to gas
- Incentivise CNG stations and electric vehicles
- Government funded deployment of a new natural gas distribution system
- 5 IEC power plants to be privatised in coming years without associated gas supply contracts

Source: Adiri Committee Interim Report (Director General of the Ministry)

Export Options



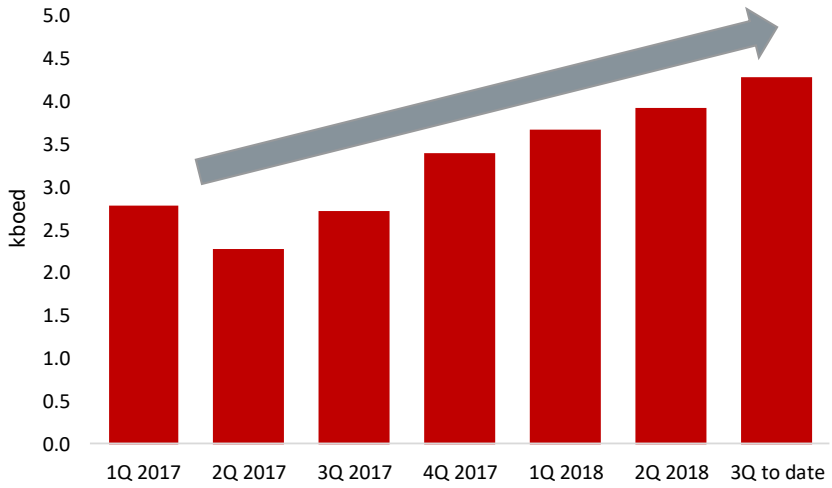
- Option for discoveries made in the five new exploration blocks
- Potential for exposure to higher pricing
- Cyprus proposal
- Longer term – East Med pipeline connecting to the European gas network via Greece and Italy

Optimising production – Prinos development & Epsilon tie-back

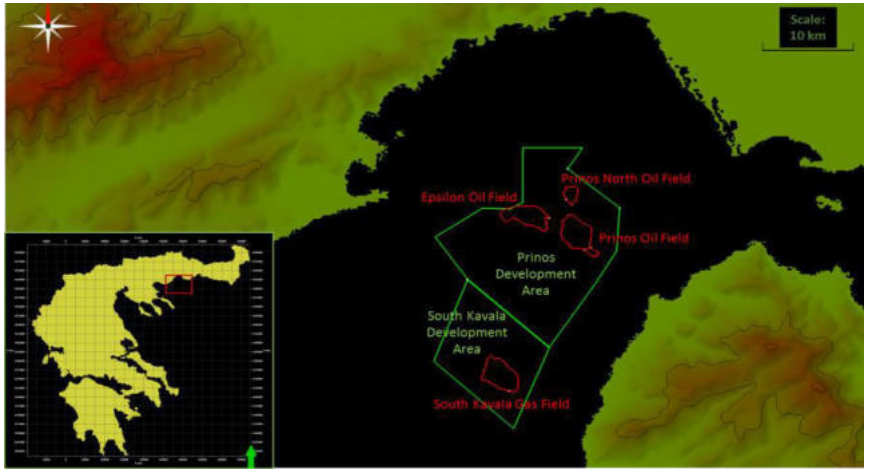
Recent progress and work programme

- 40 mmboe of 2P resource across Prinos and Epsilon
- 2018 full year guidance narrowed to 4,000 – 4,250 bopd due to replacement of Prinos infill drilling with Epsilon Extended Reach
- Production costs reduced to $19 /bbl (1H 2017: $26 / bbl). Full year guidance $17-19 /bbl
- Epsilon extended reach well spudded July 2018. First production expected 2H 2018
- Epsilon vertical drilling programme commenced August 2018. First production late 2019
- 2019 production drivers are performance of Prinos existing wells, infill wells, recompletions and workovers and Epsilon Extended Reach Well
- Prinos A platform extension committed, removing requirement for slot recovery on additional infill wells

Quarterly production growth



Prinos Location



Prinos Existing Infrastructure



Optimising production – Epsilon tie-back

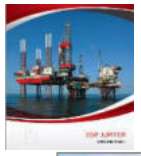
Highlights and installation sequence

- 2P reserves 18.4 million barrels (NSAI); 2P production contribution estimated at >5,000 b/d (2020, NSAI)
- GSP contracted on a lump sum EPCIC basis. Scope includes production facilities and three production wells



Energean Force drilling EWR to accelerate production

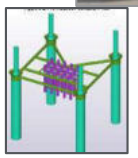
First Oil - 2H 18



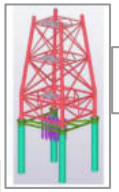
GSP Jupiter drilling rig pre-drills 3 wells



Topsides and jacket fabricated at GSP shipyard



Platform piles and base frame installed

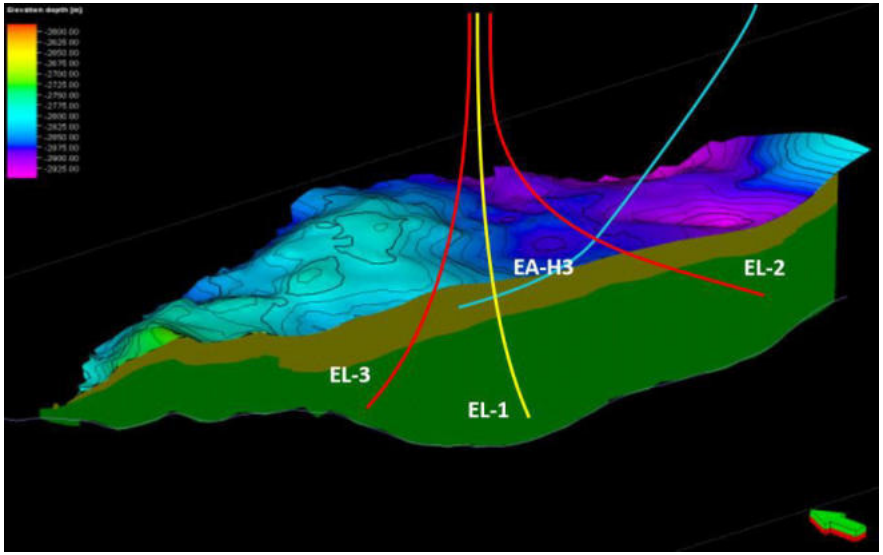


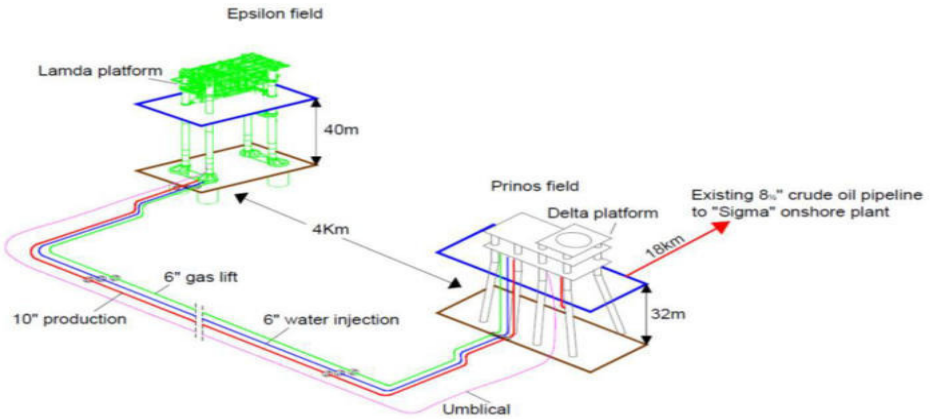
Jacket installed on top of piles



Deck installed on jacket and final commissioning

First oil from vertical wells late 2019

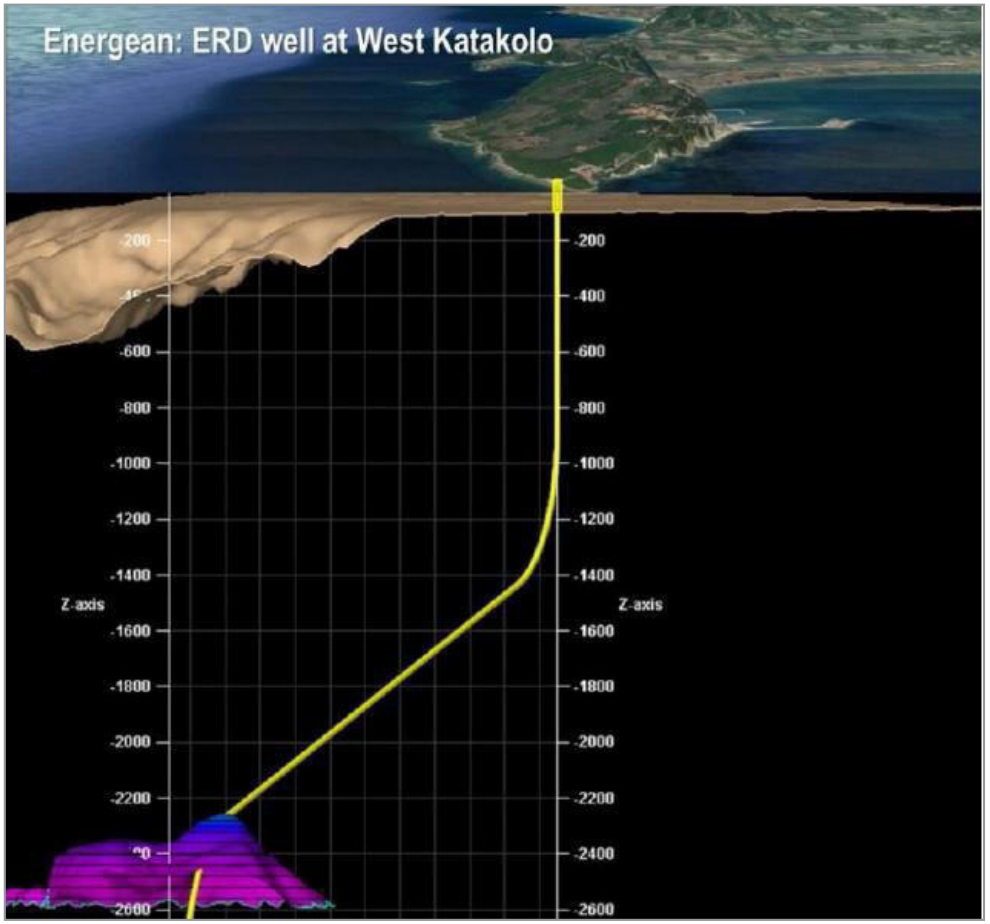




Developing reserves – optionality at Katakolo

Katakolo overview

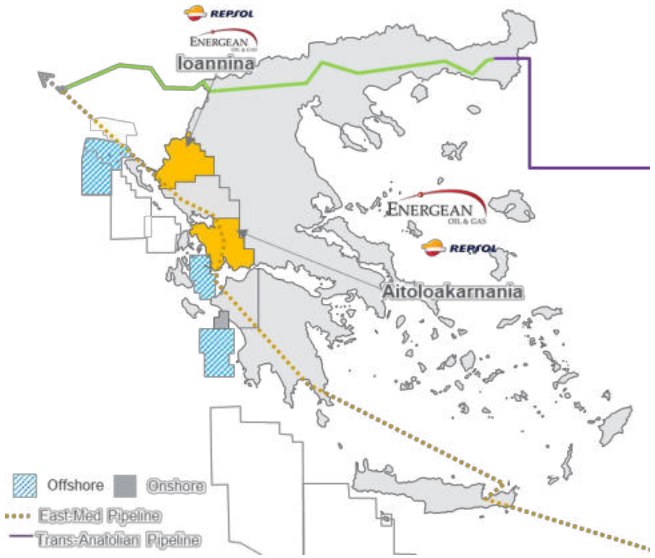
- 2P reserves of 10.5 mmbbls
- c.$100 million NPV
- $60 million development capex
- 2 wells tested
- Development plan would be to drill the first pilot hole to be converted to an injection well shortly after FID
- Environmental and social impact assessment to be submitted in 4Q 18
- Final Investment Decision or farm down to be decided in 2019



Adding more hydrocarbons - Western Greece and Montenegro

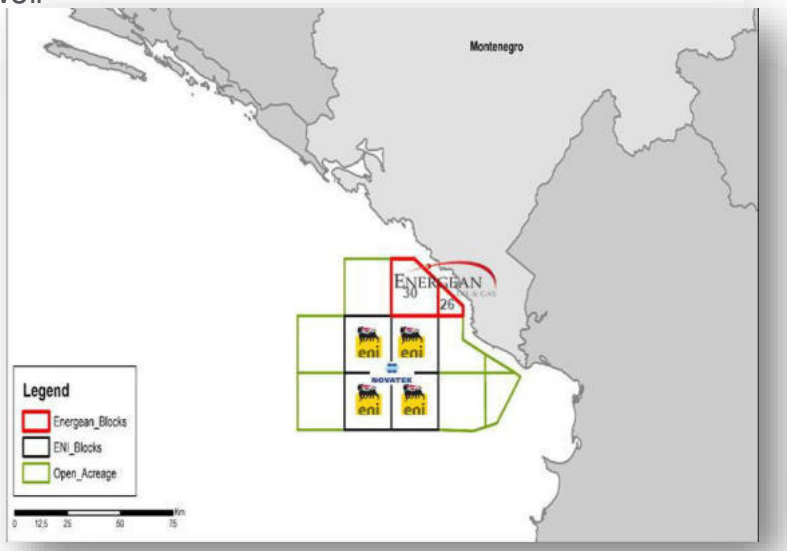
Western Greece JV with Repsol

- Repsol 60% partner and operator; pays 90% of costs to $49.9 million cap
- Seismic exploration activities have commenced



Montenegro Key Highlights

- Blocks 4218-30 and 4219-26 awarded March 2017
- (Energean 100%)
- 1.8 Tcf & 144 mmbbls unrisked prospective resources
- Low commitment (c.$5 million) first exploration phase
  - 2 block 3D seismic acquisition programme, G&G + training
- Four year optional second exploration period:
  - 1 exploration well of not less than 2,800 m
- ENI operates 4 blocks to the south, work programme commences 2019, which Energean believes includes one well



Source: Company

The next 18 months: what to watch out for

Developing Reserves	• Karish-Tanin project on track for first oil in 2021
	  • First steel cut on the FPSO – 4Q 18
	  • Hull completion – 4Q 19
	  • Topsides integration starts – Jan 2020
	• Karish Main development drilling – 3 wells in 2019
	• Aiming to fully utilise spare capacity in the FPSO
	• Export opportunities for new discoveries
	• Katakolo FID or farm down decision
		Driving additional value ahead of First Gas

Optimising Production	• Prinos infill drilling, recompletions and workovers • Early production from Epsilon via Extended Reach Well • First oil from Epsilon satellite development	**Greece FCF generative from 2019**
Adding Hydrocarbons	• Karish North – spud 1Q 19 • Upside to be targeted through Karish development drilling - D sands • Further six options on the Stena contract to de-risk 7.5 Tcf of (gross) prospective resources	**Active near-term programme**
M&A	• Continue to assess value accretive opportunities	

Q&A

Appendix

Energean Board of Directors

Non Executive Directors



Simon Heale – *Independent Non-Executive Chairman*

- Currently serves as Chairman of Gulf Marine Services, Marex Spectron and Kaz Minerals
- Prior to this served as NED and Chairman of Panmure Gordon, and as NED of PZ Cussons, Morgan Advanced Materials, Coats and Carlton Commodities



Stathis Topouzoglou – *Non-Executive Director*

- Shipowner with more than 35 years' experience in the energy transportation sector
- Founding partner of Energean Oil & Gas
- Principal shareholder and founder of Prime which has more than 35 vessels under management



Ohad Marani – *Independent Non-Executive Director*

- Board Member of Bank Leumi of Israel and member of the Investment Committee of Israel's Infrastructure Fund
- Previously Chairman of the board of Emmanuelle Energy, Israel Natural gas Lines and Alumot Investment House
- Served as Director-General of Israel Finance Ministry and also in the Israeli Embassy in Washington



Andrew Bartlett – *Senior Independent Director*

- Started his career in Royal Dutch Shell where he worked for 21 years
- 11 years of investment banking experience and former Global Head of Oil & Gas M&A and Project Finance at Standard Chartered
- Advisor to Helios Investments and NED of Africa Oil and Impact Oil & Gas
- Served as Chairman of Azonto Energy and a NED of Eland Oil & Gas



David Bonanno – *Non-Executive Director*

- Third Point representative to the Board
- Primary investment professional responsible for all Third Point's activities in Greece
- Previously worked at Cerberus and Rothschild



Robert William Peck – *Independent Non-Executive Director*

- Ambassador Peck has almost 35 years in the Government of Canada as a career Foreign Service Officer
- Resident mentor in the Human Resources Bureau at Global Affairs Canada
- Has held diplomatic roles in Nigeria, Switzerland, Algeria and Greece



Karen Simon – *Independent Non-Executive Director*

- Vice Chairman in Investment Banking with over 30 years of banking experience with JP Morgan
- Currently heads up Director Advisory Services. Also sits on the Board of Aker ASA in Norway and Youth Inc., a New York City charity serving under privileged youths
- Awarded "Most Influential Woman in Private Equity Advisory" by Private Equity News in 2010 and in 2011 and was cited several times as one of the 100 Most Influential Women in Europe, Middle East and Africa by Financial News

Executive Directors



Mathios Rigas

Chief Executive Officer

- Founding Shareholder
- Petroleum engineer with 20 years of investment banking and private equity experience mainly in the oil & gas sector



Panos Benos

Chief Financial Officer

- Chartered accountant with more than 15 years oil & gas experience both in banking & industry
- Joined Energean from Standard Chartered Bank

Energean Management Team

Executive Committee



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Panos Benos

Chief Financial Officer

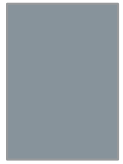
- Chartered accountant with more than 15 years oil & gas experience both in banking & industry
- Joined Energean from Standard Chartered Bank



Dr. Stephen Moore

Chief Growth Officer

- 28 years of E&P experience at Shell, Maersk Oil and Mubadala
- Previously Senior Vice President – Technical at Mubadala



Iman Hill

Chief Operating Officer

- 35 years of E&P experience
- Previously held senior roles at Dana Gas, Sasol, BG and Shell



Matt Brown

HSE

- More than 30 years HSE experience in oil & gas and chemicals
- Previously worked for Cairn, Repsol, BP and Shell

Senior Management



David Donaldson

Managing Director Prinos Asset

- Petroleum Engineer with over 30 years of industry experience
- Held senior drilling engineer positions at Shell, Eni and Halliburton



Vincent Reboul-Salze

EPCiC Project Director

- 14 years of industry experience
- Previously Lead Process Engineer for Shell / Gap KCO



Fred Riddiford

Reservoir Engineering Manager

- Reservoir Engineering with almost 40 years of experience
- Previously VP Reservoir Engineering at Mubadala



Kate Sloan

Head of Investor Relations

- 13 years experience in oil & gas
- Senior Equity Analyst for 7 years
- Chartered Accountant (ACA), having trained with Deloitte LLP

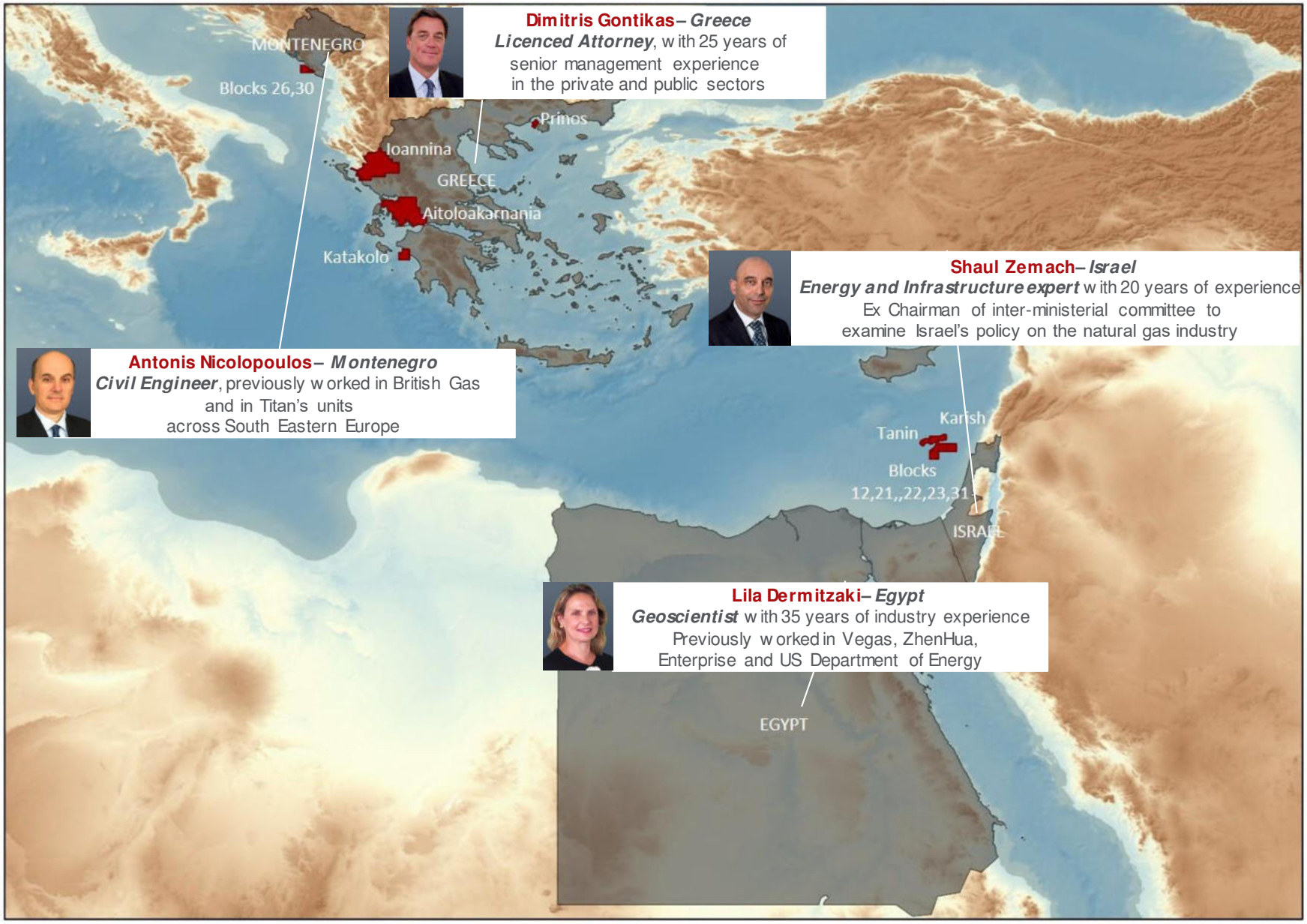


Yaron Daissy

Karish Onshore Delivery Manager & Head Regulatory Compliance

- Mechanical Engineer, 20 years in oil & gas
- Worked 15 years at Noble Energy in the Tamar and Leviathan projects

Country Managers



Dimitris Gontikas – ***Greece***
Licenced Attorney, with 25 years of senior management experience in the private and public sectors

Shaul Zemach – ***Israel***
Energy and Infrastructure expert with 20 years of experience
Ex Chairman of inter-ministerial committee to examine Israel's policy on the natural gas industry

Antonis Nicolopoulos – ***Montenegro***
Civil Engineer, previously worked in British Gas and in Titan's units across South Eastern Europe

Lila Dermitzaki – ***Egypt***
Geoscientist with 35 years of industry experience
Previously worked in Vegas, ZhenHua, Enterprise and US Department of Energy

Value creation through organic and inorganic opportunities

Disciplined Capital Allocation

Effective Project Delivery

Risk Mitigation

Operational Excellence

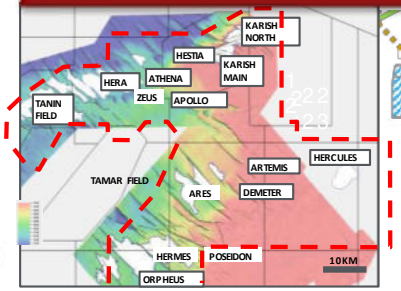
Developing reserves

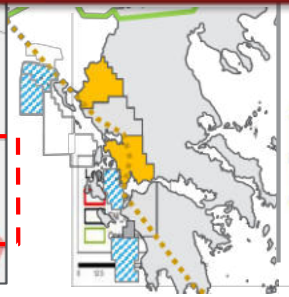


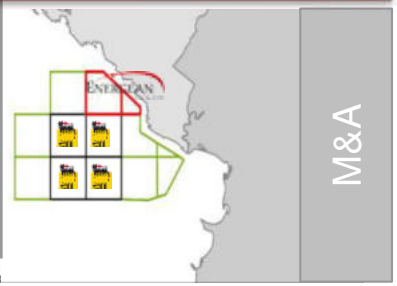
Optimising production



Adding more hydrocarbons





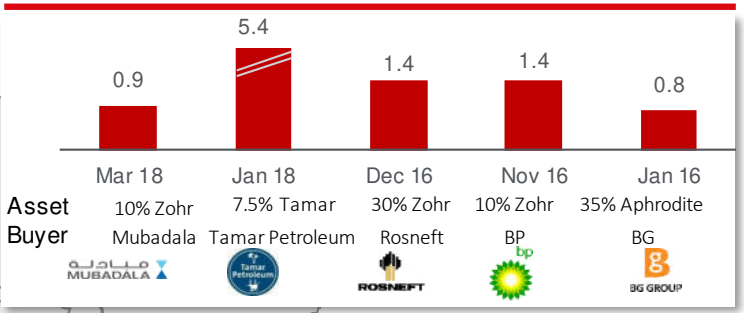


M&A

Our focus – The East Med

European Gas Market

Increasing M&A Activity



Israel

- 22 Tcf Leviathan first gas expected 2019
- Israel agreements to export gas to Egypt and Jordan
- Energean FID in 2018 for $1.6 billion investment in Karish/Tanin
- Energean identified further 7.5 TCF in 7 offshore blocks



Cyprus

- 6 - 8 Tcf Calypso discovery, ENI
- Egypt in talks to import gas from the 4 Tcf Aphrodite discovery
- Energean proposal for supply of gas from its Israeli projects
- Exxon planning exploration drilling

Greece

- Energean investing in Prinos $350 million
- Repsol partnering with Energean in Western Greece
- Exxon/Total entering the country to explore W.Greece / South of Crete
- ELPE re-entering the exploration business

Egypt

- 30 Tcf Zohr discover brought on stream
- Large Noor prospect to be drilled in 2019-2020
- Two largely unused, fully functional LNG facilities at Idku and Damietta



Export routes

- MoU signed between Israel, Greece, Italy and Cyprus supporting the East Med pipeline construction. The project is classified as European Project of Common Interest with EU sponsoring 50% of pre-FEED costs
- Option to export gas through Egypt, which operates two LNG facilities

Energean Focus Regions | Newcomers | Trans-Anatolian Pipeline | Trans-Adriatic Pipeline | East-Med Pipeline | Other Proposed Pipelines | Egypt LNG plant

Note: (1) Transaction value / boe. Source: Company Filings, Herold.

Adding more hydrocarbons – upside from development drilling

Upside to be targeted by the 2019 Karish Main Campaign

A Sands

- Main reservoir at Tamar, Leviathan & Tanin
- 8 bcm (283 bcf) GIIP potential

B sands

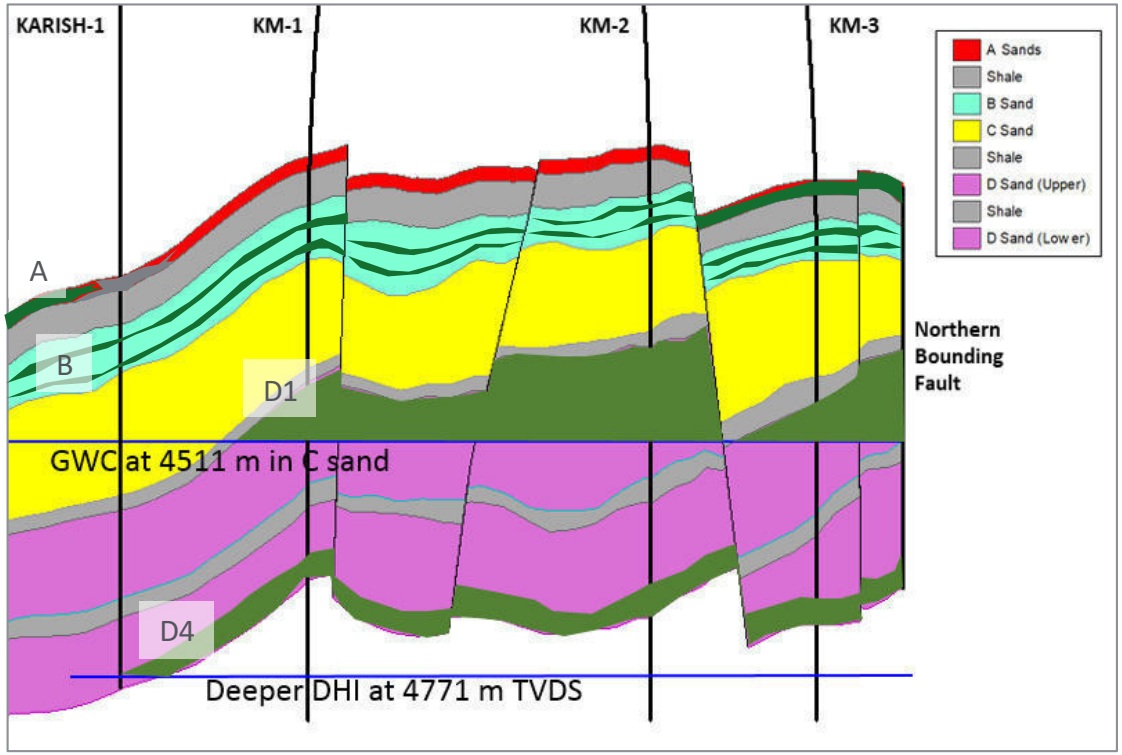
- Thinly bedded sands identified at Karish-1
- Conventional logs underestimate potential
- 15 bcm (530 bcf) GIIP potential

Upper D Sands (D1)

- Excellent quality sands identified in Karish-1
- May share common GWC with Karish C sands
- 10 bcm (353 bcf) GIIP potential

Lower D Sands (D2)

- Not penetrated at Karish
- Deeper DHI identified on seismic
- Good quality sands identified at this geological depth in Tanin-1
- 13 bcm (459 bcf) GIIP potential
- Deeper sands may have a higher liquids content due to closer proximity to the regional thermal source



Note: This slide is based on management estimates. These are not independently audited numbers

Work programme – catalyst timing

		2018		2019				2020				2021
		3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Development and Producion												
Israel	First steel cut											
	3 development wells											
	Hull leaves China											
	Topside installation, Singapore											
	FPSO sailaway											
	First gas											
Greece	Prinos infill drilling											
	Epsilon extended reach											
	Epsilon Main drilling											
	Epsilon first oil											
	Katakolo FID decision											
	New CPR											
Exploration												
Israel	Karish North											
	Development drilling upside											
	6 available slots on rig											
	Seismic on 5 new blocks											
Greece	Assess Katakolo deeper horizons											
	W.Greece seismic											
	W.Greece potential drilling											
Montenegro	Seismic											
	Potential drilling											
Corporate												
M&A	Assess new opportunities											

ENERGEAN
OIL & GAS



Analyst and Investor Visit to Greece

Wednesday 10 October 2018

Disclaimer

This presentation may contain forward-looking statements and information that both represents management's current expectations and beliefs and are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business and with any statement about the future.

Whilst Energean believes that such expectations and beliefs are reasonable in the light of the information available at this time, the actual outcomes may be materially different from the said statements, owing to factors beyond Energean's knowledge or control (or within Energean's control where, for example, the Company decides on a change in strategy).

Energean undertakes no obligation whatsoever to revise any such forward looking statements to reflect any changes (in expectations, beliefs, circumstances, events, the Group's plans or strategy or otherwise). Accordingly, no reliance may be placed on such forward looking statements or any figures therein.

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- Founding Shareholder
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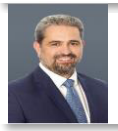
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- Chartered Accountant (ACA), having trained with Deloitte LLP



Dimitris Gontikas
Country Manager - Greece
- Licenced Attorney, with 25 years of senior management experience in the private and public sectors



Dennis Anestoudis
Exploration Manager
- Geophysicist with more than 20 years of experience.



Vassilis Tsetoglou
HSE Manager, Greece & The Adriatic
- 15 years of Experience on HSE Management in potentially high H2S environments.

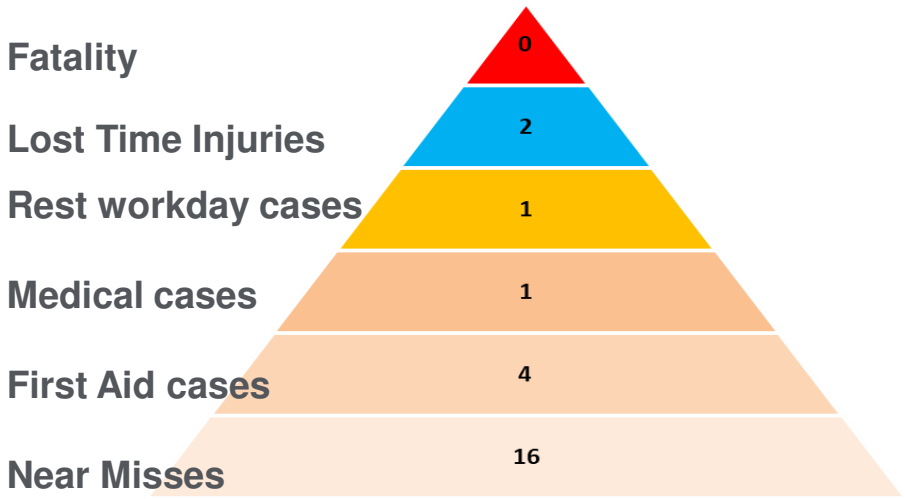


Vassilis Zenios
Project Execution Manager
- 25 years oil & gas experience, with onshore construction, pipelines and heavy lift installation.
- Previously worked in Versabar and Saipem in various worldwide locati

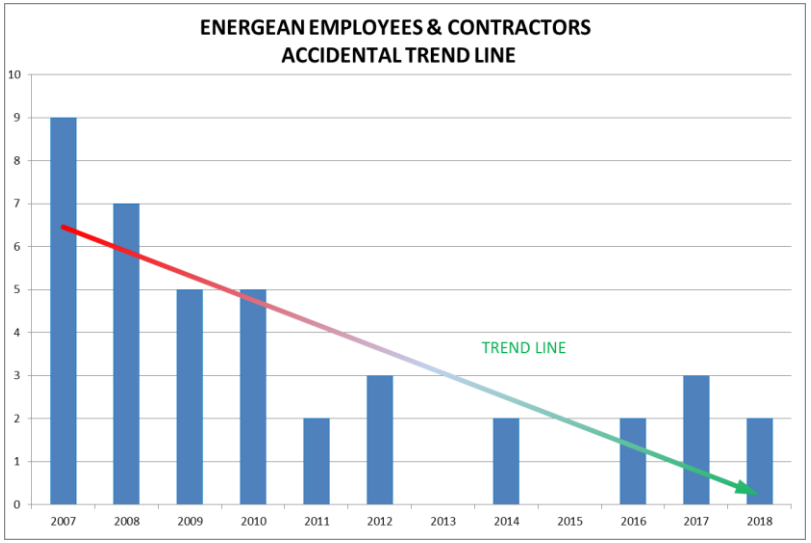


Costas Ioannidis
Kavala Oil Installation Manager
- 35 years of experience as a process engineer ensuring effective operations, maintenance and security of the facilities

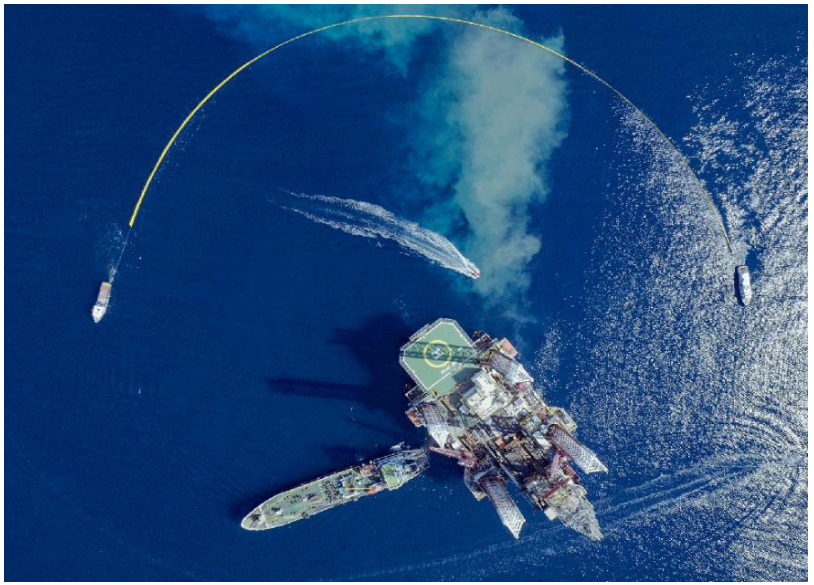
HSE Performance



2018 Total Man-hours (as of 30/09/18): 873,865



- ✓ Implementation of the Offshore Safety Directive
- ✓ Participation in the EU Emissions Trading System
- ✓ Participation in EU Blue Growth Policy through Horizon 2020 program
- ✓ Compliance with National legislation and European Directives
- ✓ OSRL membership for the provision oil spill response services
- ✓ Annual health program: zero occupational diseases
- ✓ Annual training & competency program for all employees
- ✓ Certified training courses
- ✓ Waste management through licensed companies
- ✓ Regular safety & environmental drills

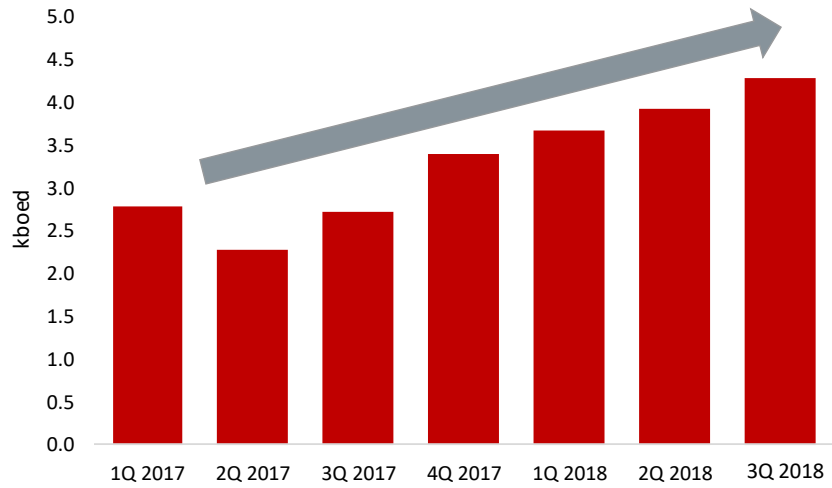


Prinos Development Overview

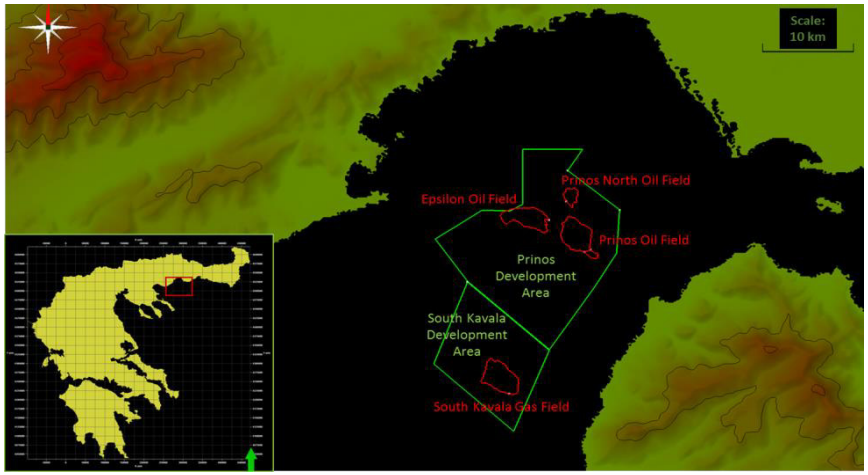
Recent progress and work programme

- 40 mmboe of 2P resource across Prinos and Epsilon
- 2018 full year guidance narrowed to 4,000 – 4,250 bopd due to replacement of Prinos infill drilling with Epsilon Extended Reach
- Production costs reduced to $19 /bbl (1H 2017: $26 / bbl). Full year guidance $17-19 /bbl
- Epsilon extended reach well spudded July 2018. First production expected 2H 2018
- Epsilon vertical drilling programme commenced August 2018. First production late 2019
- 2019 production drivers are performance of Prinos existing wells, infill wells, recompletions and workovers and Epsilon Extended Reach Well

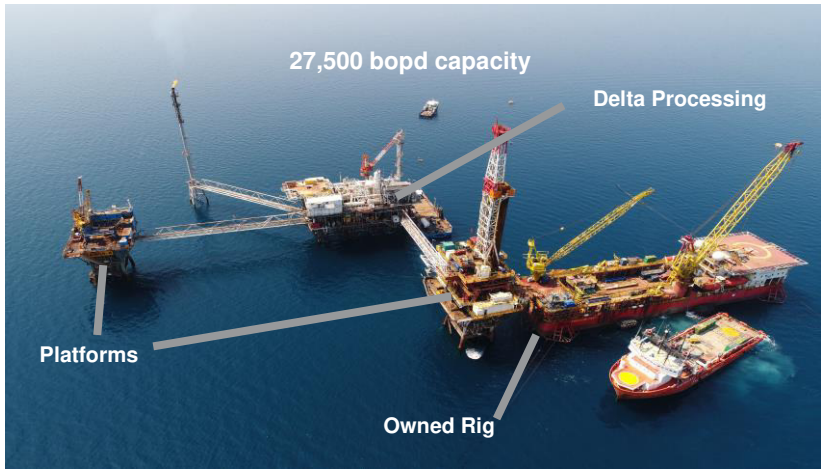
Quarterly production growth



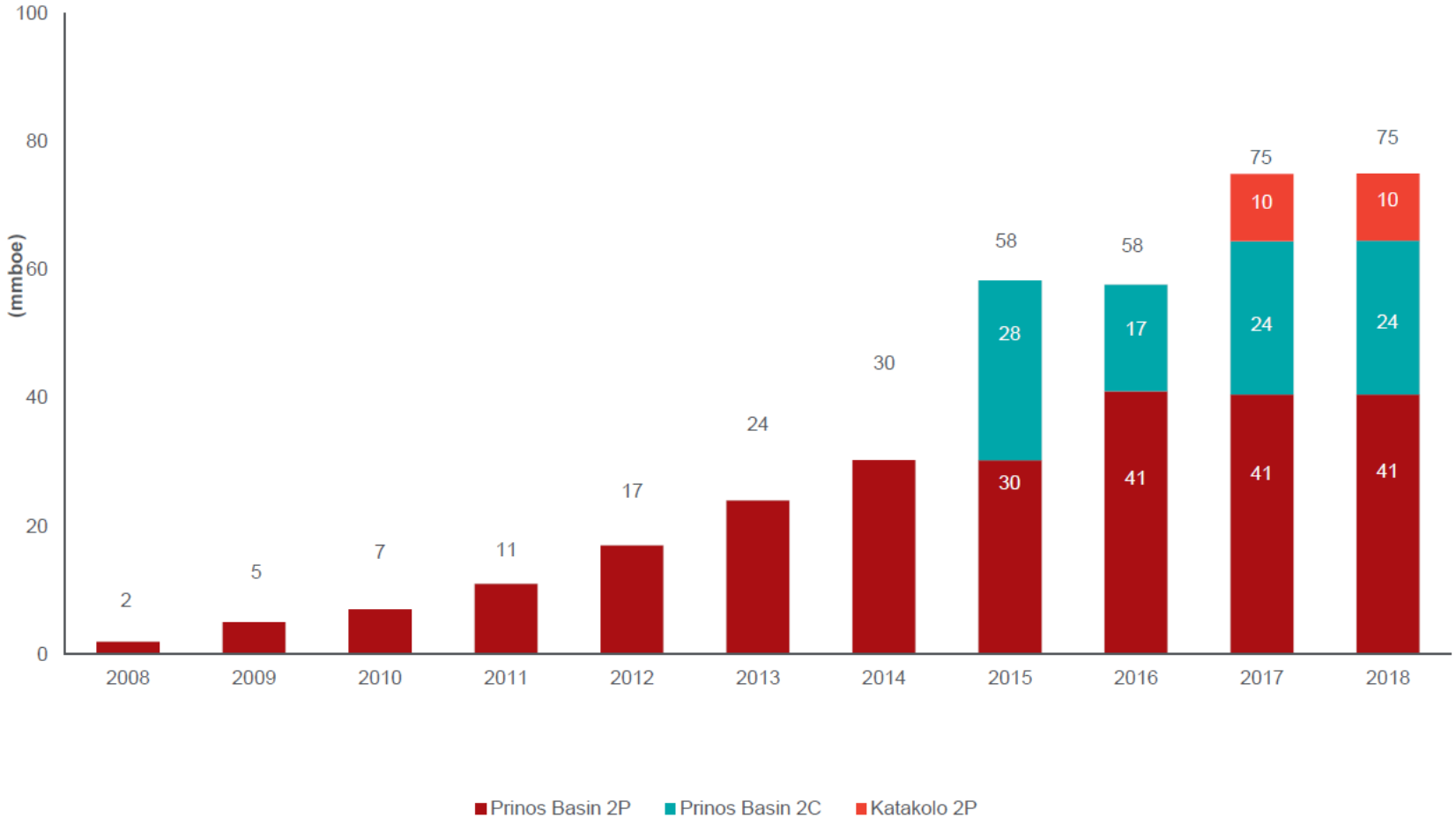
Prinos Location



Prinos Existing Infrastructure

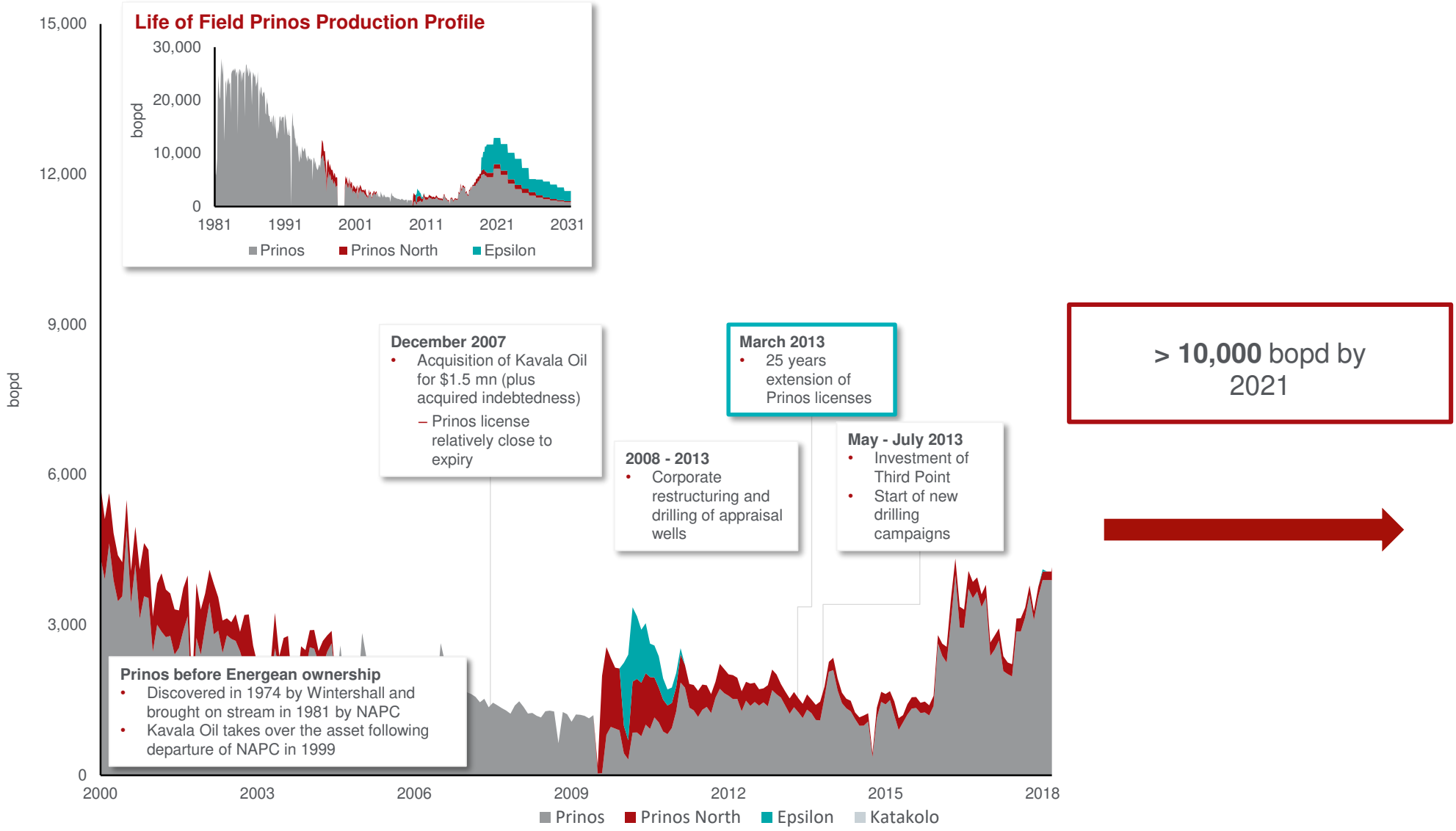


Reserves Growth History



History of Prinos

Prinos and Katakolo Production Profile



Source: Company, NSAI CPR.

Basic Terms for Prinos Asset

Fiscal Terms

- Special income tax at a rate of 20% plus a regional tax at a rate of 5% (exclusively)
- The imposition of the income tax exhausts the income tax obligations of each Co- Lessee as well as its shareholders/partners/members, with respect to the profits resulting from its contractual operations
- Exemptions are also granted on stamp duties and other indirect taxes applied on Loans and credit agreements, plus cash calls paid by each Co-Lessee to the Operator, provided that the purpose of funds granted is exclusively the financing of petroleum operations
- Tax losses can be utilized to offset taxable profits up to the termination of the companies duration

Total Royalties	Average Daily Production
0%	Up to 2,500 bbls
3%	From 2,501 to 5,000 bbls
6%	From 5,001 to 10,000 bbls
10%	> 10,001 bbls

License expiration dates and possible extensions

Field	Development License Expiration Date	Extensions Available
Prinos	Dec-24	2 at 5 years each
Epsilon	Jun-29	2 at 5 years each
Prinos North	Dec-24	2 at 5 years each
South Kavala	Nov-17	Nov-18

Abandonment Liabilities

Historical Prinos infrastructure and wells (pre-existing to the 1999 lease agreement):

- According to the Prinos lease agreement, abandonment and decommissioning liabilities of pre-existing offshore and onshore infrastructure are the responsibility of the Greek state.
- Following the signature date of the Prinos lease agreement in 1999, and the delivery to Energean of the existing wells and infrastructure, Energean is liable only for decommissioning any additional wells and any infrastructure it adds in the area.
- Energean is under no obligation to return any pre-existing infrastructure to its original (1999) condition.

Post Signature(1999):

- Energean is responsible for 50% of the liabilities for decommissioning any additional wells and any infrastructure it adds in the area and the Greek State is responsible for the remaining 50%.

Commercial Agreements

BP Offtake Agreement

- The agreement was signed in April 2013 and remains in full force, as amended, until November 2025 or delivery of 25 mmbbls of oil to BP
- c.5.0 mmbbls have been delivered to date
- Cargo sizes are scheduled for amounts not to exceed 350,000 bbls
- The US$ FOB price per bbl is based on average monthly Urals price(1), minus a price discount ($6.4/bbl), plus the API escalator(2)



Notes: Notes (1) Calculated as avg. monthly dated Brent plus the Urals differential to Brent for that period, for the month of lifting or the month prior to the month of lifting at BP's option. (2) API escalator of Average dated Brent for month M/150*(API-29.5) where API is up to a maximum of 33.

EPCIC and Financing Terms

Key EPCIC Terms

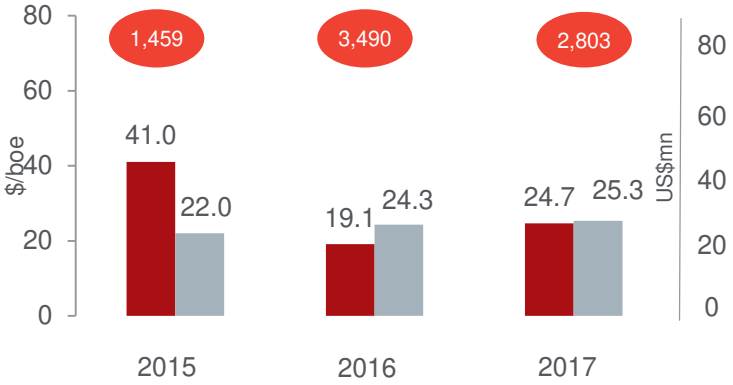
- **Contractor:** GSP Offshore
- **Scope:** Production Facilities (Lamda Platform) and three production wells
- **Lump Sum:** $88.25mn (61% Construction, 39% Drilling)
- **Warranty:** 2 years post Practical Completion
- **LD:** Liquidated damages based on day-rate for delays beyond scheduled completion of up to 15% of contract price

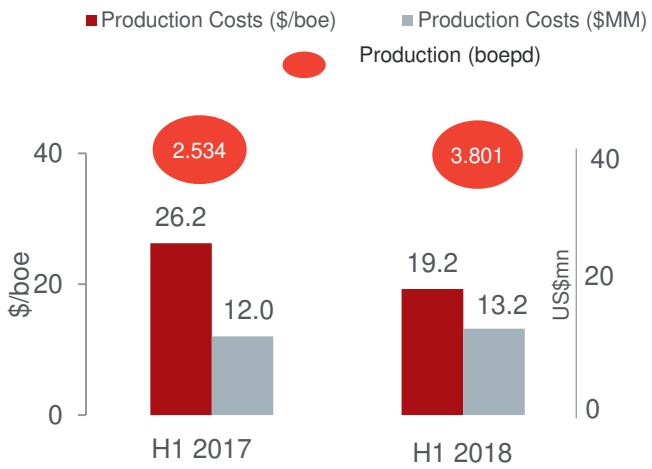
Key Financing Terms

- **Amount:** $180mn (from $75mn of the previous facility)
- **Usage:** Refinance existing debt, Epsilon development, other Prinos fields and other corporate purposes
- **Tenor:** 7 years
- **Interest:** IFI Facility (L+4.9%), Romanian Facility (L+3%)
- **Lenders:**

Financial Highlights

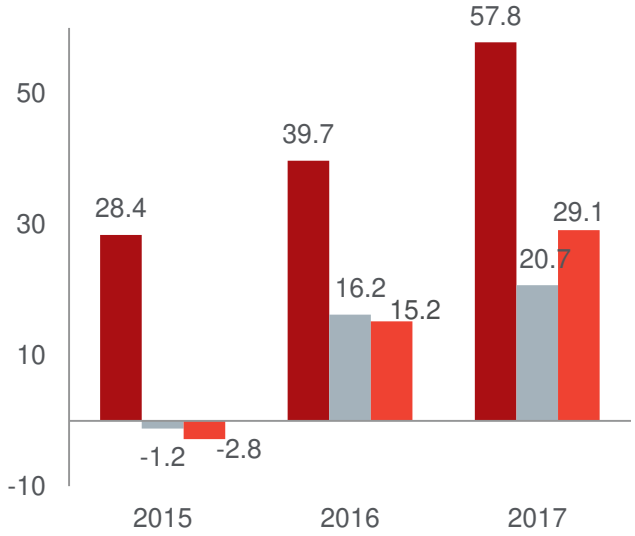
Efficient and Cost Conscious Operator

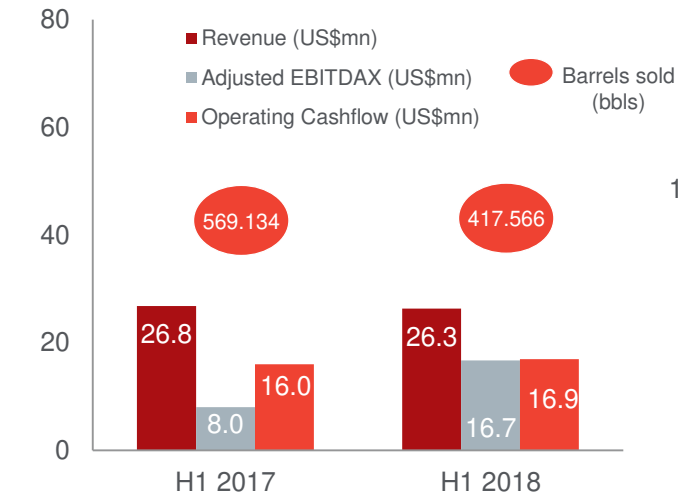




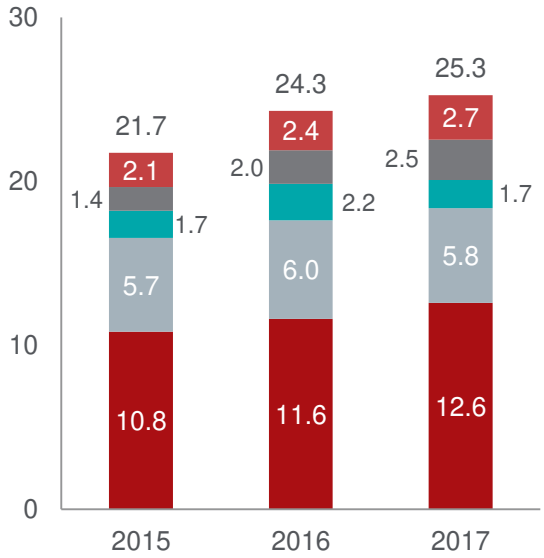
Average EURUSD FX				
H1 2018	H1 2017	2017	2016	2015
1.2104	1.083	1.1297	1.1069	1.1095

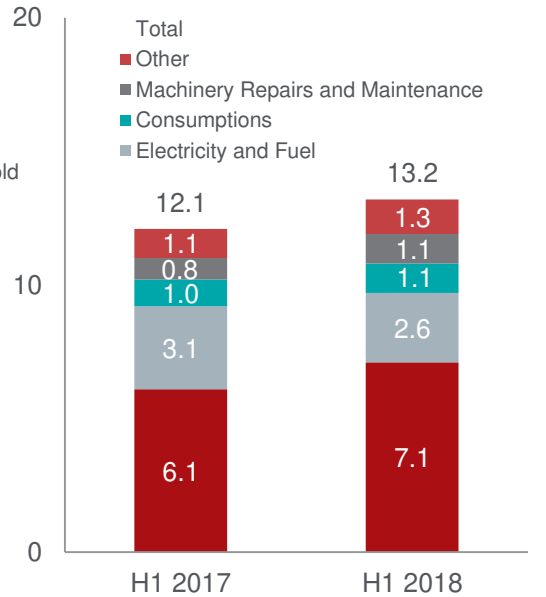
Revenue, EBITDAx and OCF (US$mn)





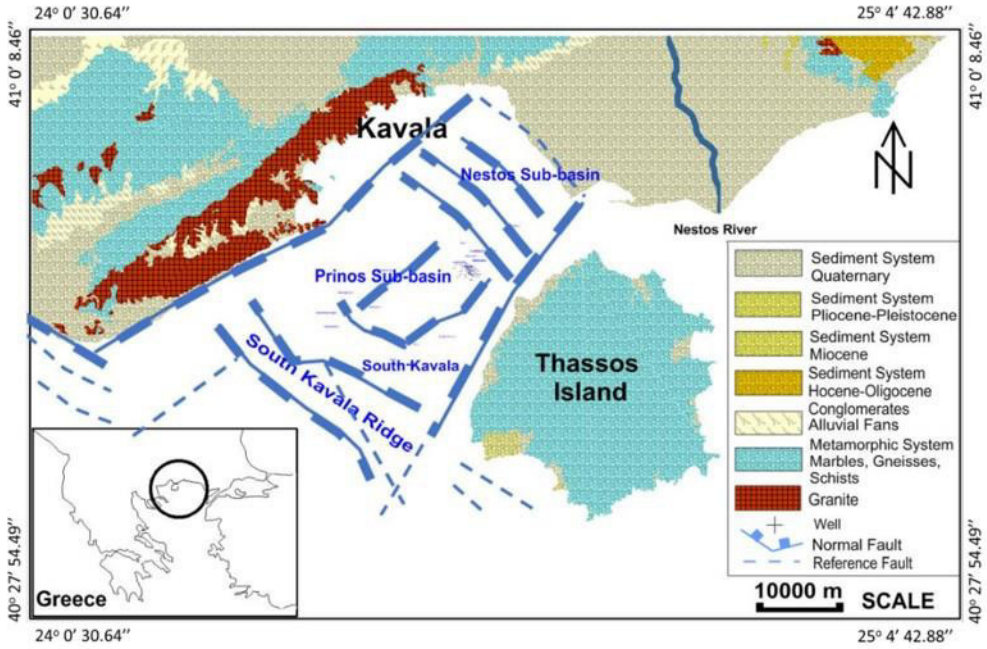
Cost of Production Breakdown (US$mn)

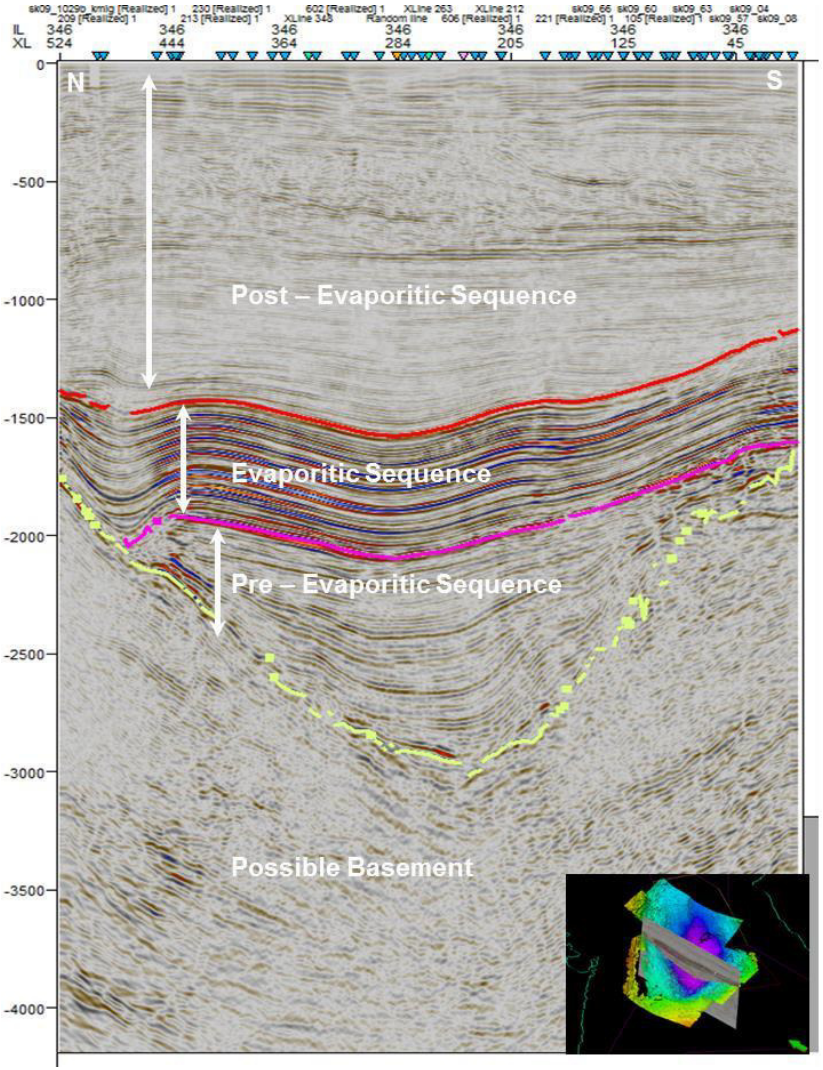




Prinos Basin Regional Review

- Prinos Basin is formed as a result of big scale extension, rotation and basement exhumation tectonics, on the North Aegean during Miocene-Pleistocene.
- Steep normal NE-SW and NW-SE faults form the deep and narrow NE-SW trending Prinos Basin (30km long and 15km wide), that rapidly filled with >5km of sediments.
- Well understood stratigraphic column divided in: the Pre-Evaporitic (Miocene), the Evaporitic (Messinian) and the Post-Evaporitic Sequences (Plio-Pleistocene).





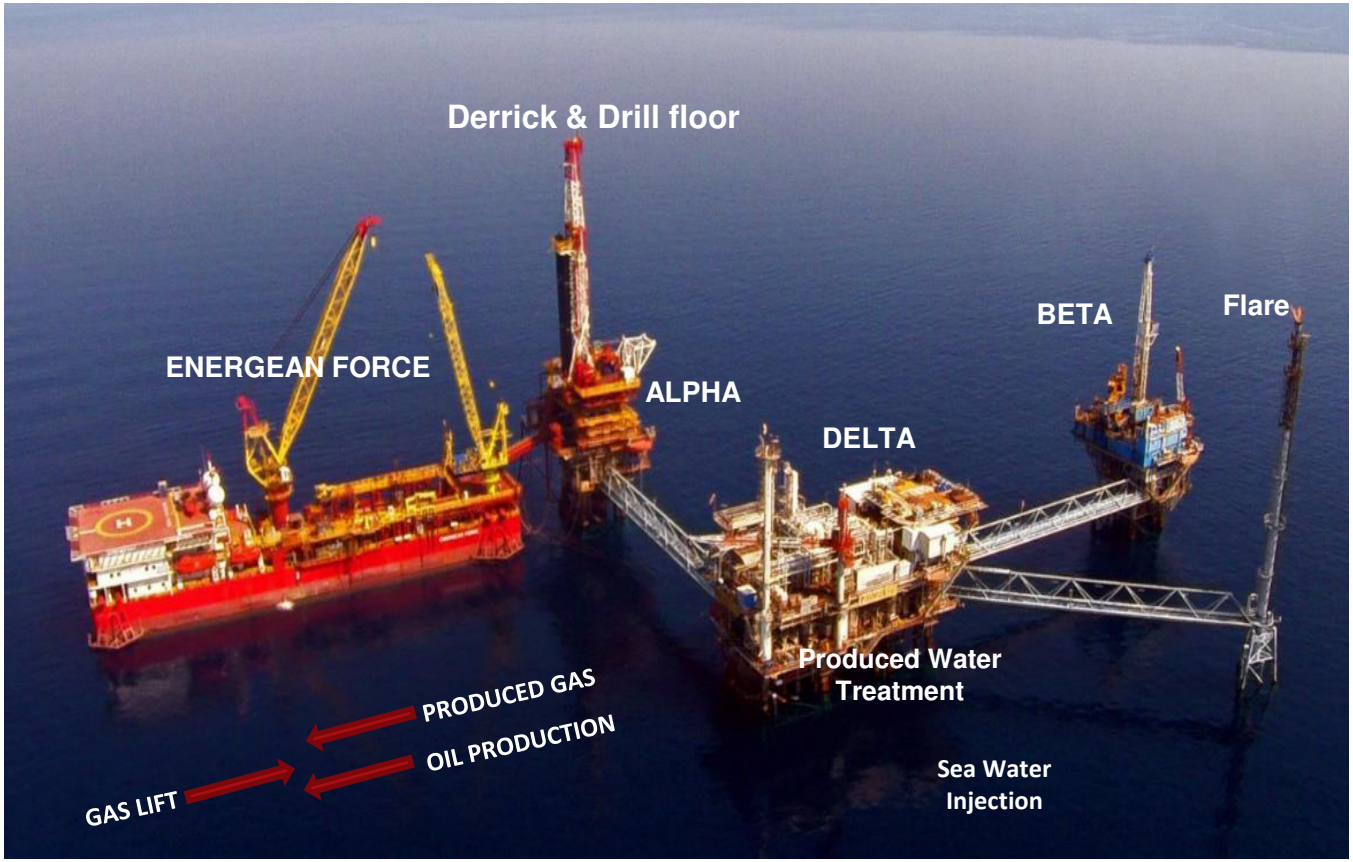
Production Offshore: Delta Complex and the Energean Force

Production Figures 3Q18:

- Oil Production: 4080 bopd
- Water Production: 10500 bwpd
- Water Injected: 17500 bwpd
- Gas Injected: 11000 Nm3/hr

How it Works

- Prinos Does not have a supporting Aquifer
- It is a closed structure
- As oil is produced the Reservoir pressure declines
- Sea Water is injected to maintain Reservoir pressure
- Gas is injected into the oil flow to lift the well







Production Onshore: Sigma Plant

1. Crude Stabilization
2. Crude Storage
3. Sour Gas Treatment
4. NGL Recovery
5. Sulphur Plant
6. Gas Recycle For Gas Lifting
7. Gas Import / Export
8. Power Plant
9. Sour Water Treatment
10. Steam Generation & Distribution



Located on the edge of a nature reserve,
Energean's neighbors are fish farms, agriculture
wild life & the sea

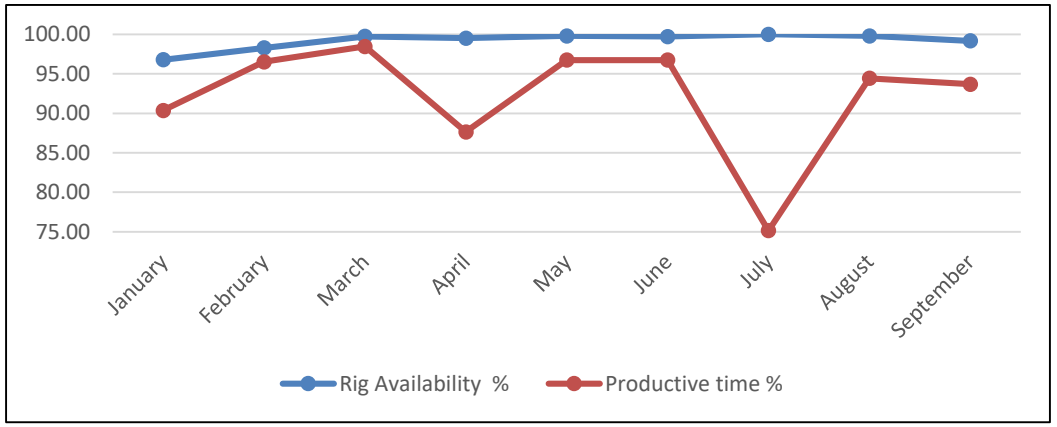


Own Drilling Rig - Energean Force

- Purchased from KCA Deutag in 2014
- Refurbished in Piraeus Greece in 2015
- Drilling in Prinos 2015 to Present
- 9 wells & 3 workovers
- Multiple Interventions

- Accommodation for 110 POB
- Normal POB while Drilling 68
- Rig & PSV Dayrate: $59k/day
- Departments
  - Drilling
  - Maintenance
  - Barge
  - Catering

Rig Availability





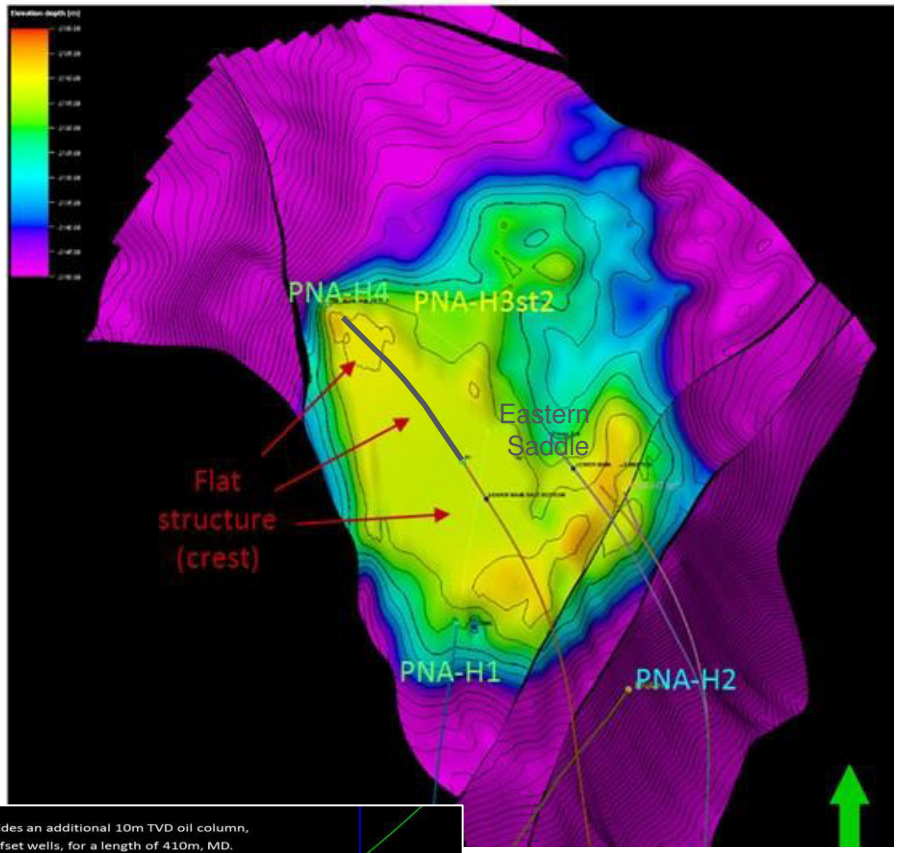
Month	January	February	March	April	May	June	July	August	September
Operating Hours Per Month	744	672	744	720	744	720	744	744	720
Operating Hours - As per program	672	648	733	631	720	697	559	703	675
Non rig related NPT (Hours)	48	12	10	86	23	22	185	40	40
Rig Equipment Related NPT (Hours)	24	12	2	4	2	2	-	2	6
GPA / Incident / Planned Maint/WOW	-	7	126	180	241	-	-	-	-
Rig Availability %	96.77%	98.21%	99.73%	99.51%	99.80%	99.72%	100.00%	99.80%	99.17%
Productive time %	90.36%	96.39%	98.45%	87.64%	96.74%	96.74%	75.13%	94.42%	93.68%

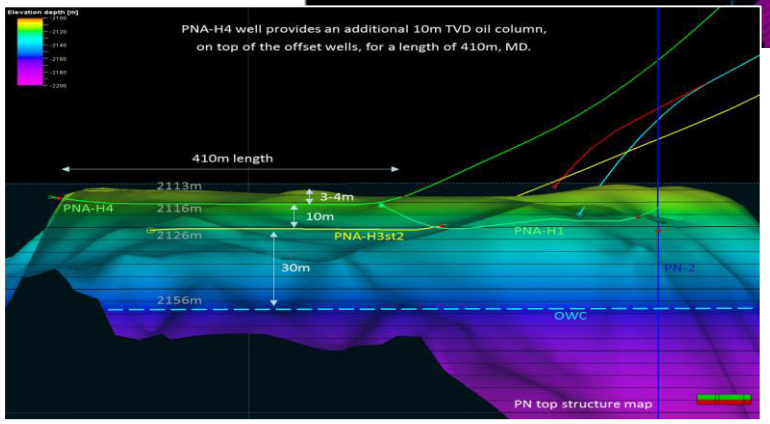
Source: Daily Drilling Report (DDR)

Prinos North

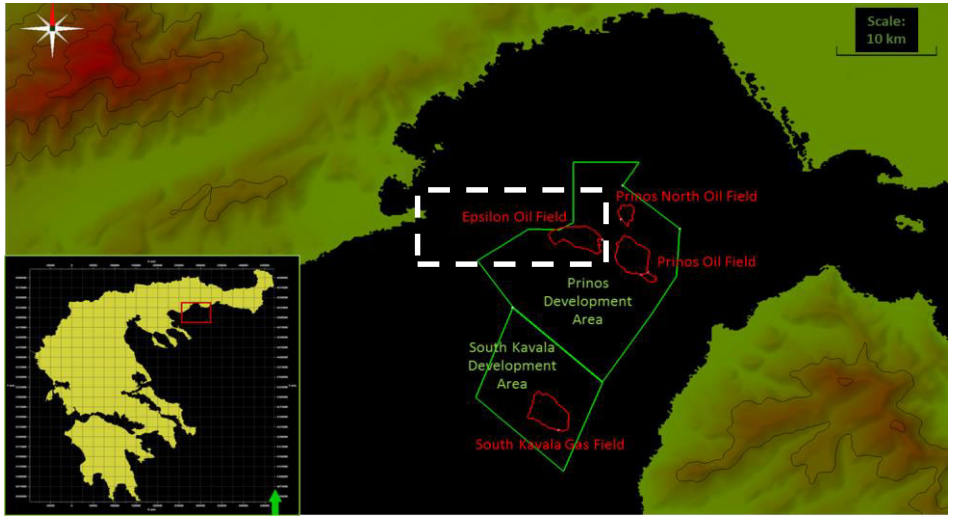
- Energean 100% working Interest,
- 3.3 mmbbls 2P Reserves (NSAI CPR 2017),
- New Well PNA-H4 drilled 2018.
- Expected production ~1500 bopd in 2H18 from PNA-H4,
- Current cumulative production 4.4 and STOIIP 24.3 mmbbls
- Recovery Factor to date 18%
- Expected Recovery Factor 30% (Prinos Recovery Factor 40%)
- Options forward:
  - a further well in the SE region.
  - appraise East Saddle
  - increase Recovery Factor
  - accelerate production

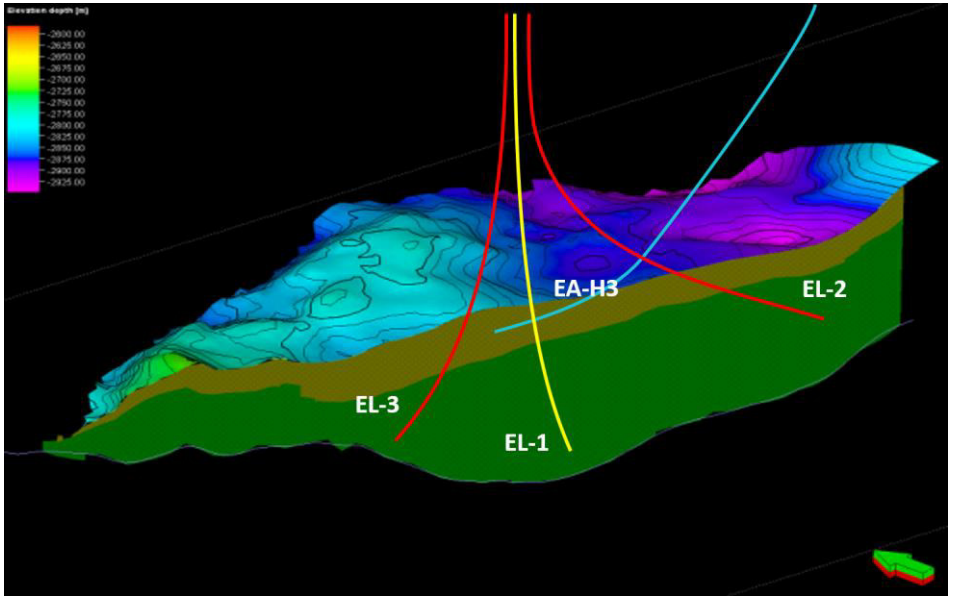
PN New Map (including PNA-H4 well data)





Epsilon – Key Highlights

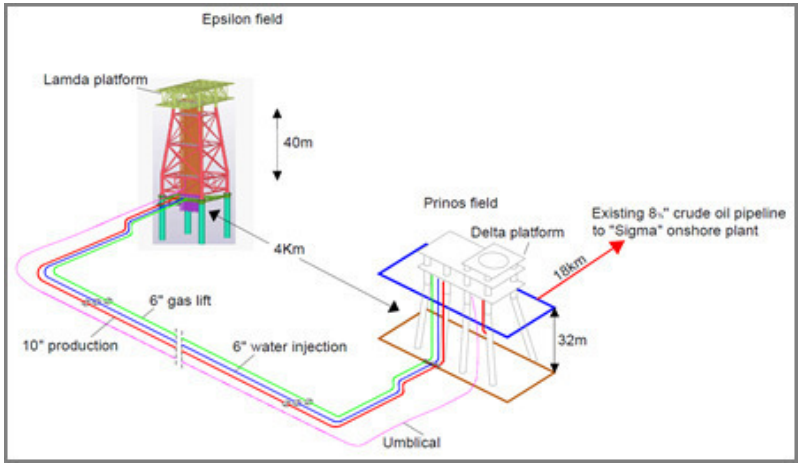


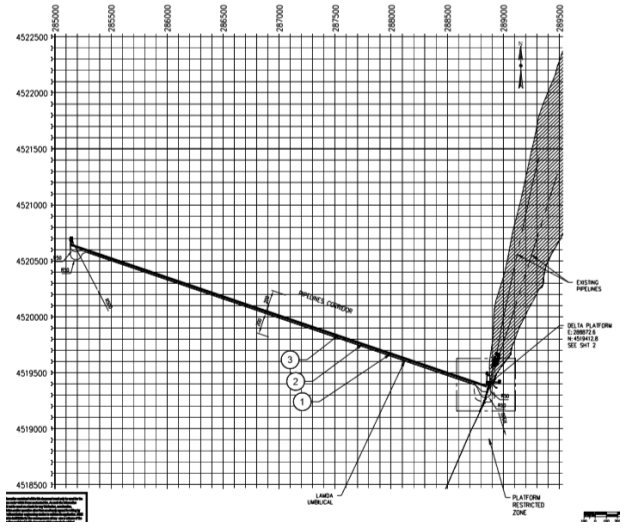


- Energean 100% working interest
- 18.4 mmbbls 2P reserves
- Expected production > 5,000 bopd in 2020
- Three vertical wells tied to Lamda platform & one Extended Reach Well tied to Prinos Delta
- First Oil accelerated through decision to drill extended reach well: expected onstream December 2018
- First Oil from three vertical wells expected in 4Q 2019
- Funded by Prinos Cash Flows & RBL Facility (L+3%)

Epsilon Development - Details

- **Epsilon field**
  - Discovered 2001
  - Appraised 2010 via ERD well drilled from Prinos
  - Similar reservoir setting to Prinos
- **Development Concept and Design**
  - Satellite tie back to Prinos complex: utilise spare capacity
  - Minimum manned facility with 15 well slots: controlled remotely from Prinos Delta
  - Gas lift, water injection, power and chemicals supplied from Delta
  - Pipeline/Umbilical construction installation and commissioning
  - Platform designed for drilling and well maintenance using Energean Tendor Assist Drilling Rig, Workover Rig or Jack up rig.
- **Project Execution**
  - First production accelerated to December 2018 via decision to drill ERW from Prinos A platform
  - TURNKEY Contractor GSP for Construction of all facilities and drilling of 3 initial vertical wells by Jack up Rig
  - Pre drilling of 3 vertical wells : 2H 2018 / 1H 2019
  - Construction and Installation of facilities completed (platform, pipelines umbilicals): Q3 2019
  - 3 vertical well completions by Jack up Rig once the platform is installed 2H 2019
  - Commissioning and Production Start FIRST OIL: 4Q
  - 5 further wells proposed to fully recover 18.4 mmbbls of 2P reserves
- **Project Development Cost**: c.$155m



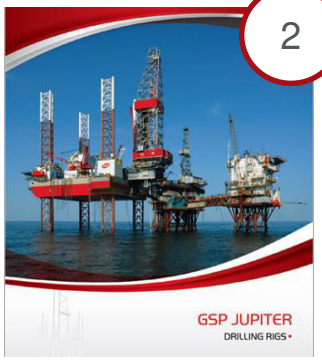


Project installation sequence

1



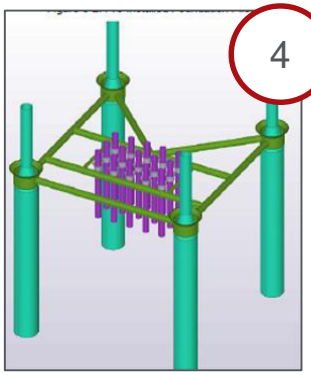
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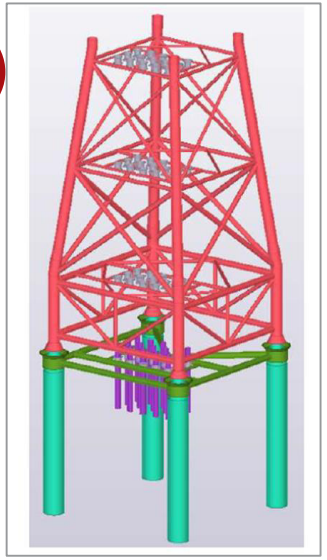
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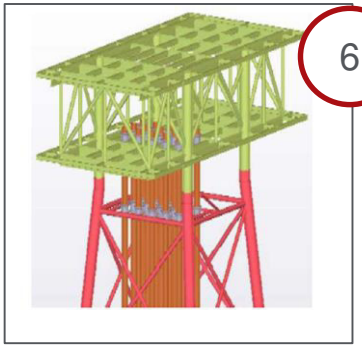
4



5



6



1. Energean Force drilling EWR to accelerate production

First Oil – December '18

2. GSP Jupiter drilling rig pre-drills 3 wells

80% complete by YE'18

3. Topsides and jacket fabricated at GSP shipyard

40% complete by YE'18

4. Platform piles and base frame installed

On Track

5. Jacket installed on top of piles

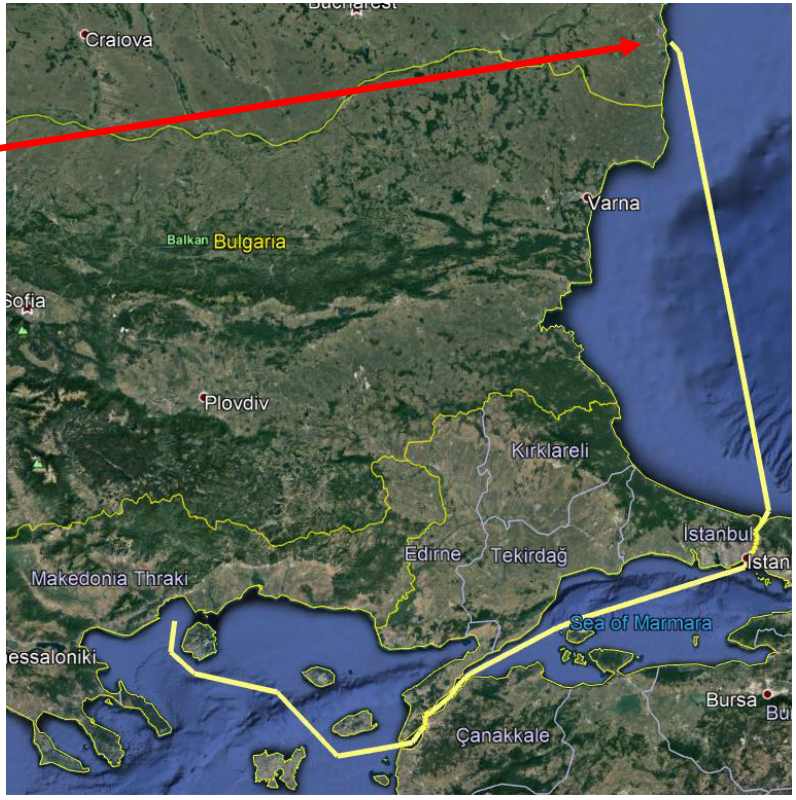
6. Deck installed on jacket and final commissioning

First oil from vertical wells 2H19

Lamda Platform Fabrication Site – Constanza Yard



GSP BASE FABRICATION FACILITY (PREVIOUS SIMILAR PROJECT) , AGINA, CONSTANZA ROMANIA



500 NM TRANSPORT FROM CONSTANZA TO PRINOS FIELD

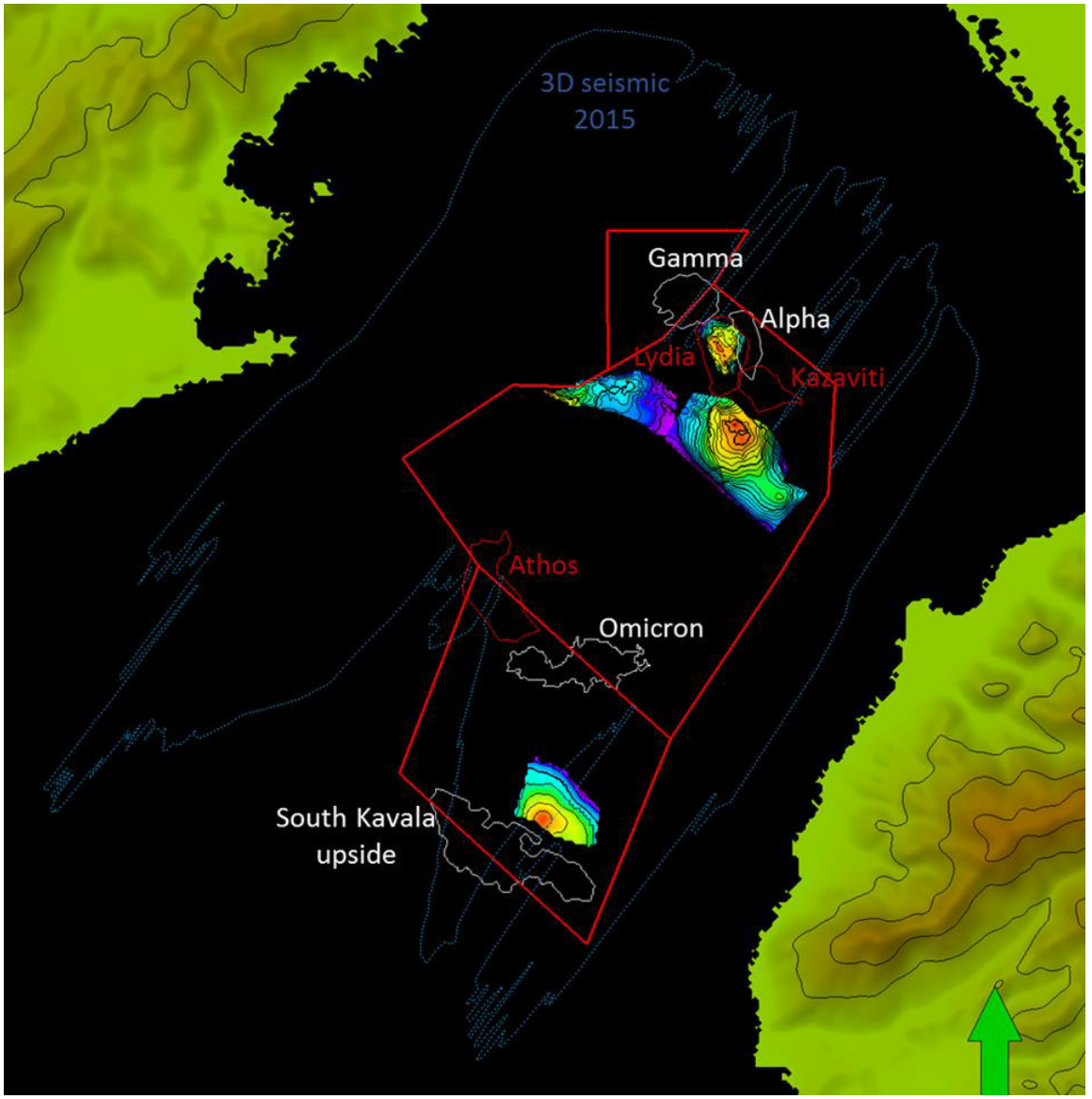
Exploration (Finding The Next Epsilon)

Prinos & South Kavala Blocks:

- Booked (NSAI CPR 2017):
  - Contingent Resources:
    - 22,9mmbbls
  - (Athos, Delta, Kazaviti Discoveries etc.)
  - Prospective Oil Resources:
    - 8,9mmbbls
  - (Alpha, Prinos SE B&C)

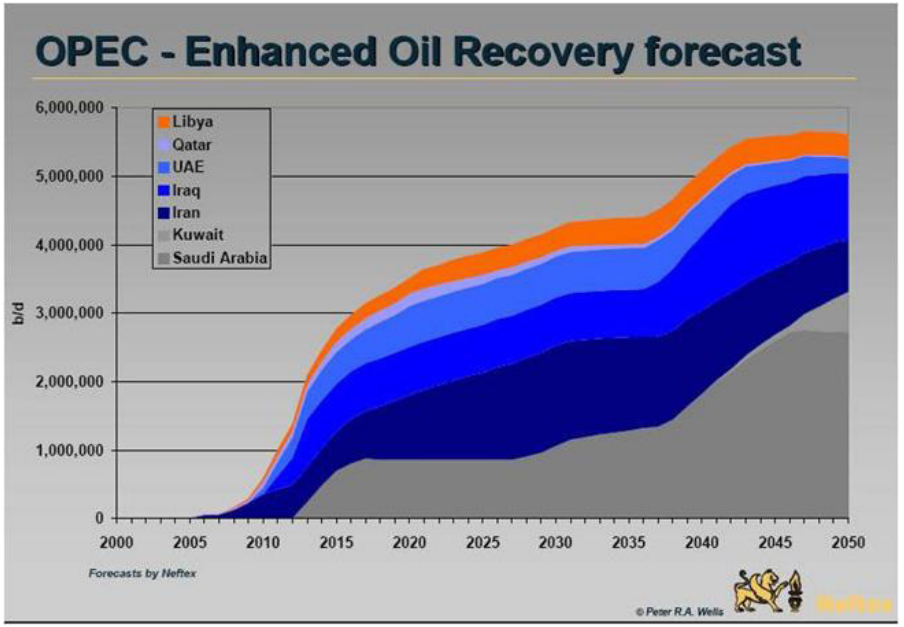
- Internal Estimates of Known
  - Discoveries/Prospects/Leads:
    - 50mmbbls

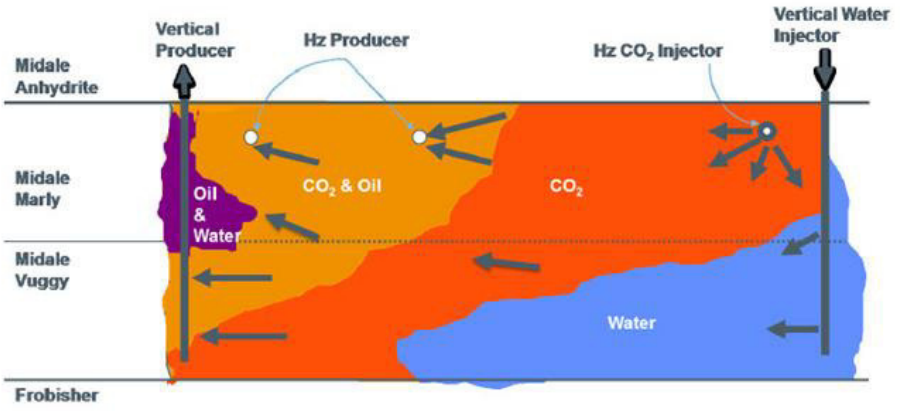
- Ongoing Studies (add to above resources):
  - Basin Prospectivity Analysis
  - Exploration Portfolio Update & Ranking



Maximising Recovery (IOR/EOR Potential)

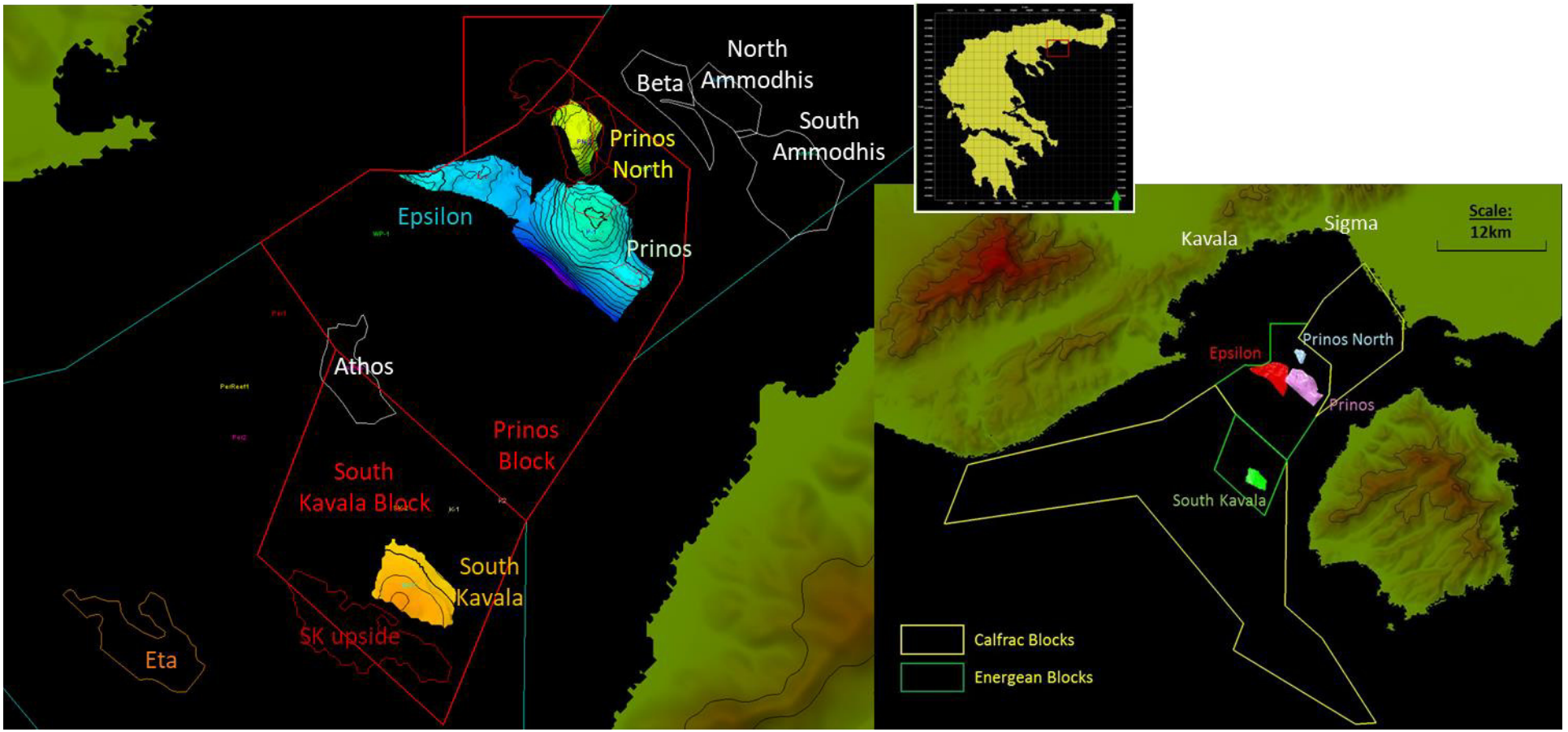
- **Prinos Field:**
  - P50 STOOIP = 289 mln bbls
  - Production to date = 112 mln bbls, Recovery Factor(Rf) = 39%
  - Water injected to maintain pressures and optimise sweep
- **IOR potential:**
  - Contingent Resources assume Rf can be increased to ~50% through further development of the Prinos Field
  - Static and dynamic model upgrades commenced
- **EOR potential:**
  - Prinos screens well to various techniques
    - Miscible flood (Acid Gas), Low saline water flood, Surfactants
  - CO2 flood study complete – availability
  - Sampling and analysis programme in parallel with infill drilling
  - Target Field Rf ~55%
- **Advantages:**
  - Proximity to shore – low CAPEX for new pipelines
  - Availability of CO2 and H2S from produced gas – reuse in an EOR scheme significantly reduces Opex
  - Availability of low saline water
  - Miscible (Acid Gas) WAG – potentially ideal option.
- **Forward Plan:**
  - Work Programme being scoped with the NTU, Athens
  - Additional Resources ~15 mmbbls
  - Target Pilot Test 2020/21





Calfrac Exploration Licenses

Calfrac Licenses (Ownership - Hellenic Petroleum 25%, Calfrac 75%)



Underground Gas Storage Project

Field Key Facts

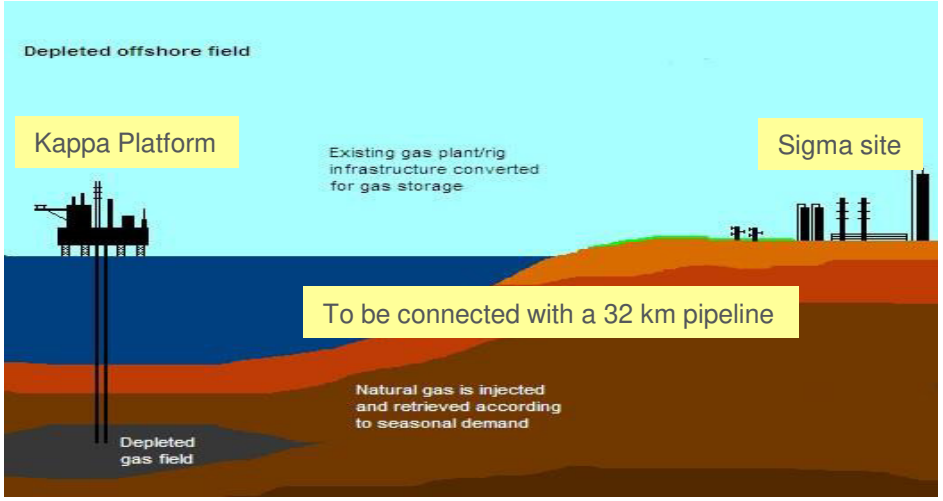
- South Kavala is an almost depleted, offshore gas field producing since 1981 (89 % RF; 52 m water depth; GIIP $0.96*10^9$ m^3)
- Turbiditic sandstone; $Ø_{avg}$ 22%; k_{avg} 100 mD
- Evaporite top seal
- No aquifer
- Dry sweet gas (0.14 mol% CO_2)
- P_{ini} 182 bar (current P_{res} 27bar), T_{res} 95 °C
- Located next to the Greek gas transportation network.
- Well integrity good

⇒ **Ideal candidate for UGS**

Current Status

- Currently, Hellenic Republic Asset Development Fund (HRADF) is tendering for an external consultant to provide financial advisory services in relation to underground facilities in South Kavala.

- Energean Oil & Gas, as the sole owner of permits and licenses in the area, has already completed the update the technical and economic model (gas market), in order to continue operate the field in the future.

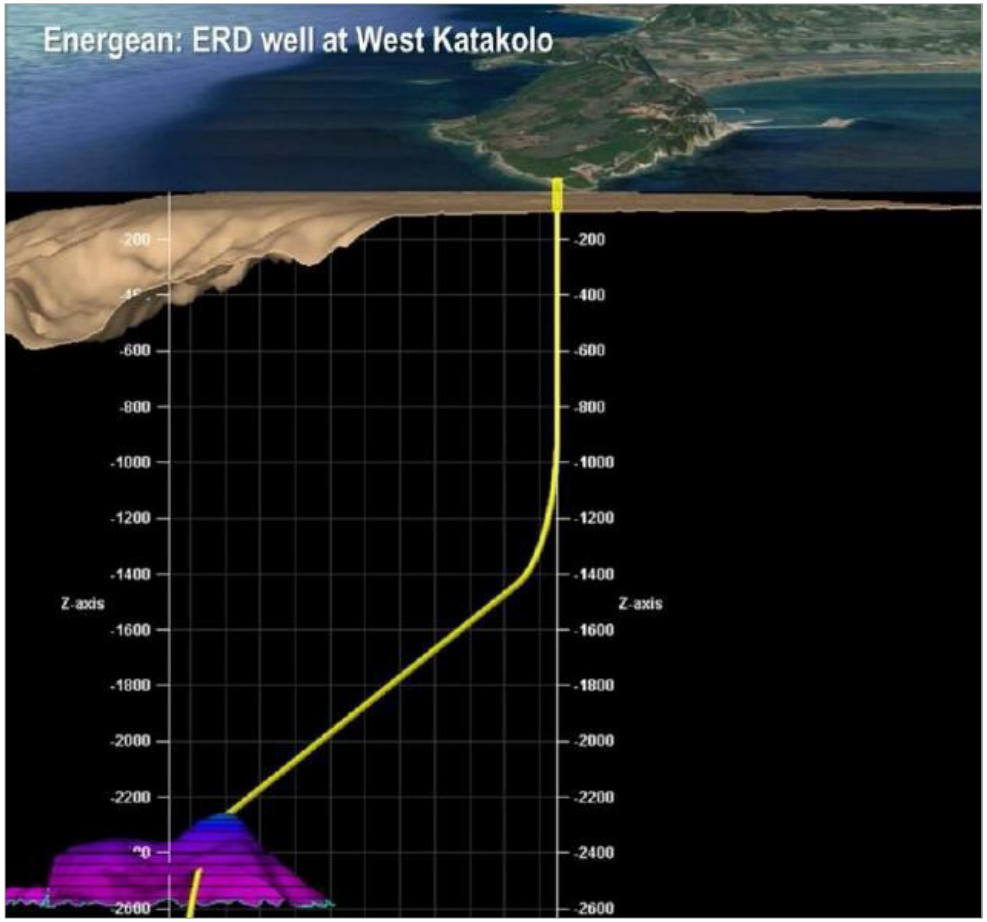




Developing Reserves – Optionality At Katakolo

Katakolo overview

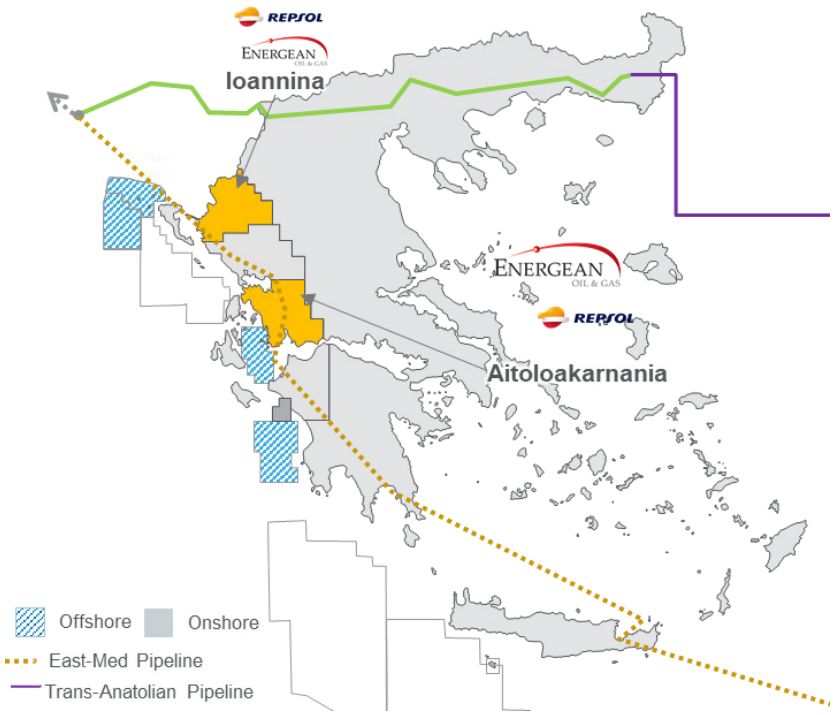
- 2P reserves of 10.5 mmbbls
- c.$100 million NPV
- $60 million development capex
- 2 wells tested
- Development plan would likely is to drill the first pilot hole to be converted to an injection well shortly after FID
- Environmental and social impact assessment to be submitted in 4Q18
- Final Investment Decision or farm down to be decided in 2019



Adding More Hydrocarbons - Western Greece And Montenegro

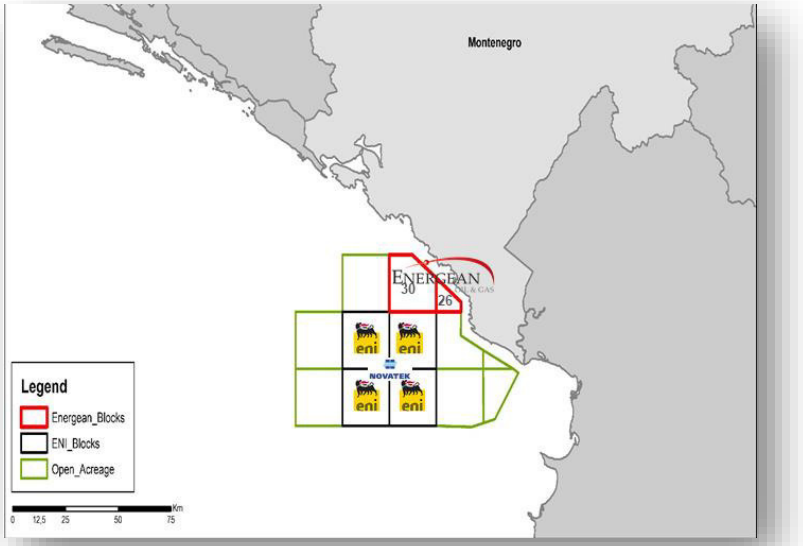
Western Greece JV with Repsol

- Repsol 60% partner and operator; pays 90% of costs to $49.9 million cap
- Seismic exploration activities have commenced



Montenegro Key Highlights

- Blocks 4218-30 and 4219-26 awarded March 2017
- (Energean 100%)
- 1.8 Tcf & 144 mmbbls unrisked prospective resources
- Low commitment (c.$5 million) first exploration phase
  - 2 block 3D seismic acquisition programme, G&G + training
- Four year optional second exploration period:
  - 1 exploration well of not less than 2,800 m
- ENI operates 4 blocks to the south, work programme commences 2019, which Energean believes includes one well



Source: Company

Prinos: Oil & Gas, Tourism And Environment Coexist

Gulf of Kavala: Over 10 Blue Flags Every Year for the Last 10 Years





Energean's HSE Mission

Transfer 37 years experience of working safely in environmentally sensitive locations in NE Greece to every area we operate

Safety of Offshore Oil & Gas Operations Directive

Thasos: Traditional tourist destination in the Aegean





Energean and TEI Kavala

Oil & Gas Technology

- Under graduate programme started in 1981
- Post-graduate program started in 2012
- Company's contribution
  - Teaching & Lectures
  - Internships
  - Scholarships





99 people are currently working in the company

- 26 from Oil & Gas Technology
- 73 from other TEI departments

Strong Relationships With The Local Communities



Kavala, Donation for the replacement of tires for the only crane vehicle of the Fire Service department of Eastern Macedonia



Support Petrochem Day, organized by students of the Chemical Engineering School of the National Technical University of Athens



Donate difibillators to municipalities of the Ioannina Prefecture, Western Greece

OUR VISION: *The company's objective is to generate sustainable growth. We are therefore committed to conducting our business responsibly, which means safeguarding the health and safety of our employees, caring for our environment, supporting the local communities in which we operate, meeting their expectations and needs and contributing to the sustainable development of those communities.*



Honour World Environment Day by cleaning with Energean's divers the seabed of the main port of Kavala



Energean Kavala BC



Support the 4th Olympia Marathon & the Association of Paraplegics in the Ileia Prefecture, Western Greece

Conclusions

- Investment in the field is attractive because of:
  i. High operational leverage (UOC goes down as production grows)
  ii. Very good fiscal term
  iii. Energean's operating capabilities
- Future growth potential is significant; of the three reservoirs (A, B &C) only the A reservoir has been exploited
- The asset is operationally self sufficient; drilling and workover plans can be executed with full control
- We understand the Prinos Basin fields and we will deliver an increase in production to >10,000 bopd by 2021

Thank You for your attention!



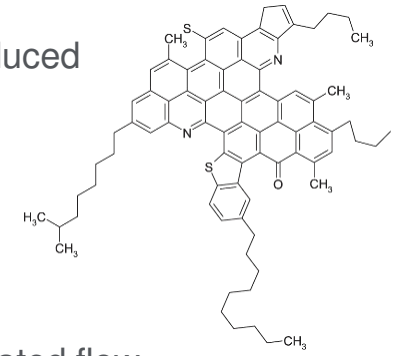
Appendix

The Asphaltene Challenge

The Ashpaltene problem & how we addressed it

Asphaltene Precipitation is the major flow assurance challenge in Prinos

Asphaltene
A complex tar like substance within the produced fluid.
- Pressure & temperature changes
- Precipitation
- Deposition
- Other factors





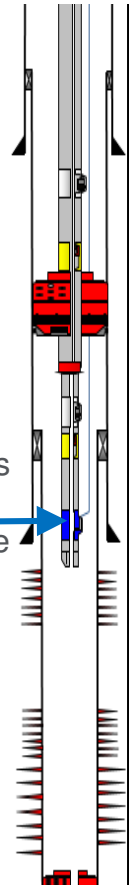
Treatment
There are 3 methods to treat Asphaltene related flow assurance
- Inhibition
- Treatment
- Prevention

Key Factors
- Bubble point
- Asphaltene precipitation envelope (ADE)
- Precipitated of asphaltene increases as pressure decreases from the upper onset pressure to the saturation pressure of the oil.
- Asphaltene onset pressure (AOP)

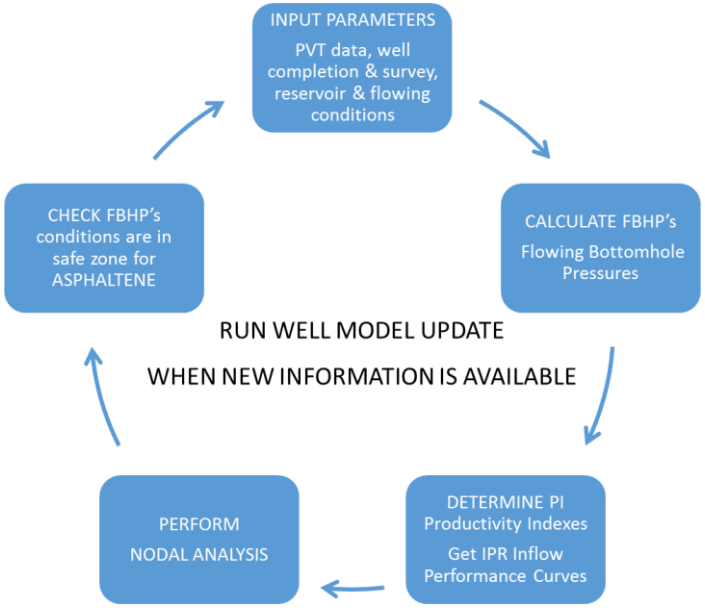


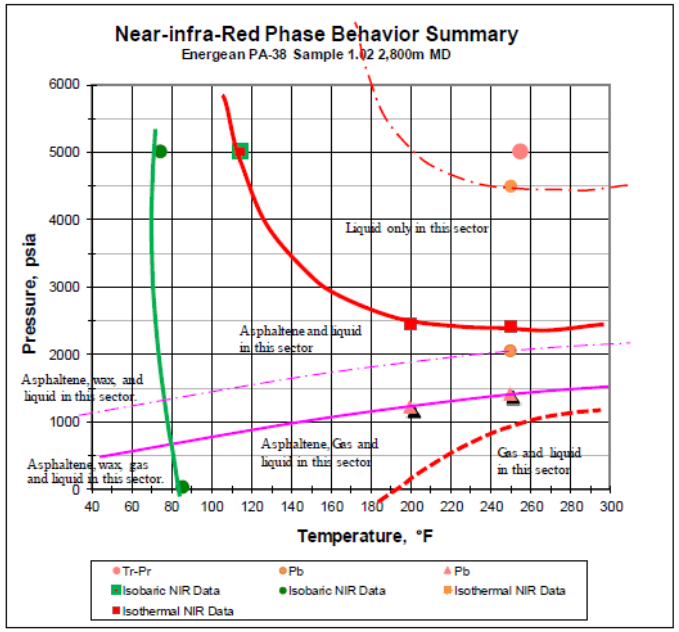
Xylene treatments pumped into well

Continuous injection Asphaltene Inhibitor



Asphaltene Management Strategy





- FBHP maintained above the Asphaltene Onset Pressure (AOP) and bubble point:
  - AOP measurements/ Phase Behaviour P&T per reservoir
  - Pressures and temperatures closely monitored.
  - Stabilize the decline in the reservoir pressures via water injection.
- Surveillance Data:
  - Surface samples periodically acquired for ADT testing.
  - Wells completion with deep chemical injection lines. Continuous injection of asphaltene inhibitor keeping the tubing's free of restrictions.
  - Optimization of Asphaltene inhibitor dosages through frequent ADT testing.
  - Daily monitoring of well test data (THP, THT flow rates, GL rate) to understand promptly sudden changes related to blockages.
  - Daily measurement of salinities and water cut incremental
- Perform flowing gradient surveys (P&T):
  - Estimate accurate FBHP's
  - Tune the VLP correlation