1090 Hamilton Street
Vancouver, B.C.
V6B 2R9
Canada

Management's Discussion and Analysis

For the Nine Months Ended
November 30, 2015
(Unaudited)

(Stated in Canadian Dollars)

Dated January 25, 2016

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The following Management's Discussion and Analysis ("MD&A") focuses on significant factors that have affected EnerGulf Resources Inc. ("EnerGulf" or the "Company") and its subsidiaries' performance and such factors that may affect its future performance. This MD&A should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended February 28, 2015 and the accompanying unaudited condensed interim consolidated financial statements for the interim period ended November 30, 2015, both of which were prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). Unless otherwise noted, all currency amounts are in Canadian dollars. "This quarter" or "current quarter" means the three month period ended November 30, 2015 and "this period" or "current period" means the nine month period ended November 30, 2015. This MD&A is dated January 25, 2016.

Forward looking information

This MD&A contains "forward-looking information and statements" that are subject to risk factors set out under the caption "*Caution regarding forward looking statements*" later in this document. The reader is cautioned not to place undue reliance on forward looking statements.

Profile and strategy

EnerGulf Resources Inc. is a publicly traded international oil and gas exploration company focused on maximizing shareholder value by targeting high impact opportunities in the world's most prospective hydrocarbon regions. EnerGulf currently holds exploration oil and gas interests in projects in the Republic of Namibia and the Democratic Republic of Congo. Also, in Albania, the Company has two chromite operations licenses, an exploration license, and has acquired rights to a pending onshore hydrocarbon license, which is pending governmental action.

The Company currently derives no revenues from its oil and gas or chromite interests. Revenues, if any, are dependent on the successful completion and placing into production of the Company's oil and gas and chromite properties.

The Company is a reporting issuer in British Columbia and Ontario and trades on the TSX Venture Exchange (the "TSXV") under the symbol "ENG" and on the Frankfurt Exchange under the symbol "EKS".

Overall performance

The following highlight's the Company's overall performance for the three and nine months ended November 30, 2015:

- Net loss of $413,013 and $784,626 for the three and nine months ended November 30, 2015, respectively, compared to $530,978 and $1,525,928, respectively, during the same periods in the prior year;
- Cash balance of $87,060 at November 30, 2015, compared to $7,933 at August 31, 2015, and $107,976 at February 28, 2015;
- Working capital deficiency of $965,636 at November 30, 2015, compared to $972,470 at August 31, 2015, and $623,978 at February 28, 2015.

On September 29, 2015, the Company completed the acquisition of Columbus Copper Corporation ("Columbus Copper") by way of a plan of arrangement. Pursuant to the plan of arrangement, each outstanding common share of Columbus Copper was exchanged for 0.4937 of an EnerGulf common share. A total of 9,200,000 common shares were issued.

On April 14, 2015, the Company announced the receipt of a Letter of Extension granted from the Government of the Democratic Republic of Congo ("DRC"), whereby extending the first five year period of the Production Sharing Contract *(see Discussion of operations for details)* between the government and the Company for the Lotshi Block.

Discussion of operations

The Company is an oil and gas development entity, focused on the selection, acquisition, and exploration of hydrocarbon properties. EnerGulf maintains an interest in acquiring additional key hydrocarbon properties worldwide. The Company's financial success will be dependent upon the extent to which it can make discoveries and on the economic viability of any such discoveries. The development of such assets may take years to complete and the resulting income, if any, is difficult to determine with any certainty. To date, the Company has not produced any revenues. The sales value of any oil and gas discovered by the Company is largely dependent upon factors beyond its control, such as the market value of the commodities produced.

There are significant uncertainties regarding the prices of oil and gas and the availability of equity financing for the purposes of exploration and development. There has been a dramatic decline in the price of oil over recent months and there is no indication of how long prices will remain depressed. The future performance of the Company is largely tied to the development of its property interests and other prospective business opportunities as well as the overall financial markets. Financial markets are likely to be volatile, reflecting ongoing concerns about the stability of the global economy and weakening global growth prospects. Uncertainty in the financial markets has also led to increased difficulties in borrowing and raising funds. Companies worldwide have been affected negatively by these trends. As a result, the Company may have difficulties raising equity financing for the purposes of oil and gas exploration and development, particularly without excessively diluting the interests of existing shareholders. These trends may limit the ability of the Company to develop and/or further explore its current oil and gas exploration properties and any other property interests that may be acquired in the future.

In addition to the risks outlined in this MD&A, EnerGulf has identified the extreme volatility occurring in the financial markets recently as a significant risk for the Company. As a result of the market turmoil, investors are moving away from assets they perceive as risky to those they perceive as less so. Companies like EnerGulf are considered risk assets and as mentioned above are highly speculative. The volatility in the markets and investor sentiment may make it difficult for EnerGulf to access the capital markets in order to raise the capital it will need to fund its current level of expenditures.

<u>Republic of Namibia – Block 1711</u>

Gross prospective oil resources evaluation

In February 2012, the Company received a prospective oil resources report for four prospects and nine leads on Block 1711, including a mean estimate of 3.166 billion barrels of potentially recoverable oil. The report was prepared by independent oil and natural gas reservoir engineers Netherland Sewell and Associates, Inc. ("NSAI") of Dallas, Texas. NSAI estimates the unrisked gross (100 percent) prospective oil resources for the prospects and leads as of December 31, 2011, to be:

	Gross (100%) Unrisked Prospective Oil Resources (MMbbl)			
	Low estimate	**Best estimate**	**High estimate**	**Mean estimate**
Total	742	2,749	6,108	3,166

To view the NSAI report in its entirety as reported on February 23, 2012, visit www.sedar.com or www.energulf.com *(As per NI 51-101 section 5.9, There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.)*

Petroleum agreement overview

On June 7, 2013, EnerGulf was granted a 15% working interest under a new Petroleum Agreement (the "New PA") approved by the Government of the Republic of Namibia for Block 1711, offshore Namibia. The parties to the New PA are the Government of the Republic of Namibia, Gazania 148 Investments (Pty) Ltd ("Gazania") and EnerGulf Namibia Ltd. ("EnerGulf Namibia"). The initial Operator is Shaanxi Yuyang Petroleum Technology Engineering Co. Ltd. Gazania will own a 75% working interest, EnerGulf Namibia will own a 15% working interest and NAMCOR, the National Oil Company of Namibia, ("NAMCOR") will own a 10% carried interest to production. The agreement is subject to a government royalty of 5%. The New PA replaces in its entirety the 2006 Petroleum Agreement. The New PA and related Exploration License have an initial term of four years commencing June 7, 2013, may be renewed by the Government twice for additional two year periods, and provide for the following work programs and minimum expenditures:

Initial Exploration Period (4 years), the minimum exploration expenditure is US$40,000,000 and the work program includes:

- Acquire at least 2,500 square kilometers of 3D seismic lines to image some of the existing prospects in the south-western quadrant of Block 1711;
- Process the seismic data via pre-stack depth migration;
- AVO processing for post-rift prospects;
- Optional processing through Reverse Time Migration;
- Acquire sea-floor piston cores over vents identified with side-scan program; and

- Procure drilling vessel and drill one exploration well to the base of the syn rift and not less than a depth of 5500m below the sea level.

The First Renewal Period (2 years) and the Second Renewal Period (2 years) each have a Minimum Exploration Expenditure of US$40,000,000 and each include the requirement to drill one exploration well to a depth based on the results of the previous wells. Gazania has provided the Government with the guarantees required to cause the Petroleum Exploration License to be issued, a $4,000,000 Bank guarantee (equal to 10% of the first period exploration requirement) and a guarantee of performance of the party's obligations.

On May 20, 2014, Gazania and EnerGulf Namibia entered into a Strategic Exploration Agreement ("SEA"), under which Gazania will carry the Company for all value add costs ("Value Add Costs"), including costs to acquire and process 3D seismic and if necessary or appropriate, reacquire 3D seismic data, as approved by the Technical Advisory Committee ("TAC") and Minister of Mines and Energy ("Minister"), to acquire and process all other exploration data (excludes exploration well) required under the Petroleum Agreement as approved by the TAC and the Minister, to develop two independent geological and geophysical constructs for Block 1711, and to engage qualified professionals to prepare reports, maps and presentations for Block 1711 in accordance with good oilfield practices and international oil and gas industry standards. In addition, Gazania will carry the Company for all NAMCOR costs allocable to EnerGulf Namibia under the New PA. As part of the SEA, any costs incurred until a consensus drill site has been approved by the TAC, will be borne by Gazania, after which additional exploration costs will be borne by the Company up to its working interest under the New PA. All costs incurred to the identification of the approved drill site would contribute towards the $40,000,000 initial work program. Management's expectation is to commence joint marketing efforts during the consensus drill site development process.

A Joint Operating Agreement ("JOA") has been negotiated by Gazania and EnerGulf Namibia, to which NAMCOR is a party. The JOA will further define their respective rights and obligations relating to exploration of Block 1711 and, if warranted, production and will address such matters as operator responsibilities, operational procedures and priorities, payment obligations and differences between payment obligations and participating interests, accounting procedures, cost recovery for the carried NAMCOR interest, transfers of interests, and removal and replacement of the operator. The JOA has not been approved by NAMCOR or signed by Gazania.

Certain annual commitments are required under the New PA, in order for the agreement to continue in good standing. As Gazania is responsible for the maintenance of these commitments, the Company is reliant on them for the continued good standing of the property.

As at November 30, 2015, the Company had incurred total expenditures of $12,523,293 (February 28, 2015 - $12,586,268) on this project.

Geological overview

EnerGulf participated in the drilling of the Kunene No. 1 on the block, in 2008, to a total depth of 5,050m. The well encountered Hydrocarbon shows (C1-C5 in two zones), which indicates a proven working petroleum system for the block.

The northern half of the block has 3D seismic coverage and the entire block has 2D seismic coverage.

The Company completed an updated analysis for Block 1711 in 2011, which was presented to the Operating Committee, Technical Advisory Committee, Ministry of Mines and Energy, and Non-Operators. The exploration studies revealed multiple prospects and leads supported by amplitude anomalies and other hydrocarbon indicators. The Block 1711 prospect portfolio includes a Tertiary Turbidite play, Syn-Rift play, both of which have giant field analogs in Angola and Brazil, and a Basement play. Fossil evidence from the Kunene No. 1 well points to the potential for multiple Tertiary-age turbidite sandstone prospects. Turbidite sandstone reservoirs are common and prolific in West Africa, Brazil and Deepwater Gulf of Mexico. Regionally, turbidite sandstone reservoirs account for more than 20 billion barrels of producible reserves in Angola (Blocks 14, 15, 17 18 offshore Luanda), Nigeria (Agbami, Akpo and Bongo), Equatorial Guinea (Zafiro and Alba) and the Campos Basin of Brazil (Marlim and Albacora). The Company's extensive study also provided significant new information concerning the hydrocarbon potential of the Syn-Rift play, including possible seismic evidence of salt on Block 1711. The Syn-Rift rocks in Block 1711 are stratigraphically similar to the Pre-Salt rocks of the Santos Basin of Brazil (Lula, Guara and Lara) and in the Upper Congo Basin (Malongo and M'boundi Fields – also near EnerGulf Africa's Lotshi Block). These plays currently contain more than 15 billion barrels of producible reserves, and are still developing. The Company geologists have also developed several large prospects in a third play on Block 1711. They believe that this play has not been tested in the area and involves large "basement" horst blocks that form extensive ridges. These horst blocks are adjacent to the syn-rift half-grabens, but are believed to be comprised of older, pre-rift rocks. There is evidence of Karoo-age clastic rocks with excellent reservoir potential onshore near the eastern margin of Block 1711, and the Company geologists suggest that these extensive ridges are comprised of pre-rift Karoo-age rocks. Some geologists might consider this play to be part of the syn-rift or pre-salt play, but the Company has chosen to consider this as a separate play because of the uncertainty concerning the age of the potential reservoir rocks.

Historical timeline:

- March 2005 - EnerGulf Namibia, a wholly owned subsidiary of the Company, enters into Memorandum of Cooperation with NAMCOR (www.namcor.com.na) establishing a working relationship with regard to joint ventures in oil and gas exploration, development and production opportunities in Namibia, in particular Block 1711.
- March 2006 – EnerGulf Namibia is formally assigned a 10% working interest in Block 1711, and the Ministry of Mines and Energy issues Petroleum Exploration License.
- June 2006 - The Company engages NSAI, an independent international petroleum consulting firm located in Dallas, Texas (www.netherlandsewell.com) to prepare an assessment of the Prospective Resources for Block 1711 based upon the geological and geophysical data and information held by the Ministry of Mines and Energy.
- October 2006 – A Joint Operating Agreement is entered into between Sintezneftegaz Namibia Ltd, as Operator, and Petro SA (National Oil Company of South Africa), NAMCOR, BEE Group and EnerGulf Namibia, as Non-Operators.
- October 2007 – The Ministry of Mines and Energy approves the Environmental Impact Assessment Report from Risk Based Solutions of Namibia for Block 1711, and issues Environmental Clearance for drilling operations.
- November 2007 – Technical Advisory Committee Meeting in Moscow which selects the Kunene No. 1 for the first drill site.
- April 2008 – Drilling operations commence for the Kunene No. 1. EnerGulf Namibia nonconsents in completion attempt. The Kunene No. 1 was determined to be non-commercial. However, hydrocarbon gases C-1 through C-6 were encountered in the well, which indicatives a proven petroleum system for the block.
- April 2010 – The Ministry of Mines and Energy extend the Petroleum Exploration License for two years.
- September 2010 – EnerGulf Namibia is appointed as interim operator for the Kunene No. 1 and Block 1711.
- 2010 – 2011 – EnerGulf Namibia reviews and analyzes the Kunene No. 1 data and information and updates its geological and geophysical construct for Block 1711.
- 2010 – 2011 - The Company engages NSAI to update its initial assessment of the Prospective Resources for Block 1711 based upon the post Kunene No. 1 data and information.
- October 2011 – EnerGulf Namibia presents to the Ministry of Mines and Energy in Windhoek, Namibia, a complete analysis of the Kunene No. 1 and further evaluation of the hydrocarbon potential of Block 1711.
- February 2012 – The Company receives the updated NSAI Prospective Resources Report for Block 1711.
- June 2013 – EnerGulf Namibia enters into a Petroleum Agreement with Gazania, and NAMCOR (National Oil Company of Namibia), for offshore Block 1711, covering 8,891 square kilometers (2.2 million acres), which grants Gazania a 75% working interest, EnerGulf a 15% working interest, and NAMCOR a 10% carried working interest.
- October 2013 – The Ministry of Mines and Energy of the Republic of Namibia issues a Petroleum Exploration License to Gazania, EnerGulf Namibia and NAMCOR.
- May 2014 – EnerGulf Namibia and Gazania enter into a Strategic Exploration Agreement.

Democratic Republic of Congo – Lotshi Block

Gross prospective oil resources evaluation

In March 2011, the Company engaged DeGolyer and MacNaughton ("D&M"), an independent international petroleum consulting firm located in Dallas, Texas (www.demac.com) to prepare an assessment of the prospective resources on EnerGulf's Lotshi Block and the report was delivered in May 2011. The report has been prepared in accordance with Canadian NI 51-101 and other Canadian, United States and International standards and covers the potentially recoverable oil on seven oil prospects on the Lotshi Block, mean estimate of 313 million barrels. The report concludes: Prospective resources in seven oil prospects have been identified in the 507 square kilometer Lotshi Block, DRC. The prospective resources presented below are based on the statistical aggregation method. Estimates of the gross prospective oil resources, as of December 31, 2010 are summarized as follows, expressed in English units in thousands of barrels (10^3bbl).

	Gross Prospective Oil Resources Summary				
Prospect	**Low (P90) estimate (10^3bbl)**	**Best (P50) estimate (10^3bbl)**	**High (P90) estimate (10^3bbl)**	**Mean estimate (10^3bbl)**	**Probability of geological success, P_a (decimal)**
Dallas	23,441	53,333	125,268	67,139	0.235
Durango	9,790	22,394	50,455	27,962	0.183
Houston	12,560	28,353	61,876	34,630	0.180
I35	4,906	13,728	36,024	18,059	0.202
Midland	19,396	46,890	121,808	60,645	0.194
Odessa	20,858	46,652	108,142	57,772	0.178
Seabrook	14,811	36,842	93,765	47,237	0.196
Statistical aggregate	**207,679**	**299,368**	**428,573**	**313,176**	**0.198**

The report does not consider the potential resource contribution from any reservoirs above the Loeme Salt, or from the Chela formation. The Chela formation is the main reservoir in the giant Rabi-Kounga field in Gabon and in smaller fields nearby in Cabinda. There have also been shows reported in the Chela in other wells near the Lotshi Block, but the stratigraphic position of the Chela directly underneath the Loeme Salt make it a difficult target to map seismically and therefore for the purposes of this report, it is considered of significant, but secondary importance to the exploration targets considered therein. D&M will issue an updated report that includes Chela prospective resources when that data is provided. EnerGulf has developed two Chela prospects for the Lotshi Block. The current report covers the targeted Bucomazi, Lucula and other presalt reservoirs.

To view the D&M report in its entirety as reported on May 13, 2012, visit www.sedar.com or www.energulf.com *(As per NI 51-101 section 5.9, There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.)*

Production Sharing Contract Overview

On November 16, 2005, EnerGulf Africa Ltd. ("EnerGulf Africa") was granted a Contrat De Partage De Production ("Production Sharing Contract" or "PSC") by the DRC, for the Lotshi Block, containing 507 square kilometers, lying approximately 33 kilometers from the west coast of the DRC. The PSC grants EnerGulf a 90% working interest and COHYDRO, the National Oil Company of the DRC, ("COHYDRO") a 10% carried working interest. The Company incorporated EnerGulf Congo SARL ("EnerGulf Congo") to act as the Operator. The PSC was ratified and approved by Presidential Decree on March 12, 2008. The Ministry of Hydrocarbons issued a Permis d' Exploration (Exploration Permit) for the Lotshi Block on October 31, 2009. EnerGulf Africa and COHYDRO entered into a Contrat D' Association (Joint Operating Agreement) for the Lotshi Block on February 5, 2009. The PSC and Exploration License were made effective as of October 31, 2009 (date of the Exploration License) by Memorandum Agreement dated October 25, 2010. The PSC and related Exploration Permit have an initial term of five years commencing October 31, 2009 and may be renewed by the Government twice for additional five year periods. The PSC expired on November 1, 2014. On April 3, 2015, the Company received a letter from the Director of the Cabinet of the Prime Minister of the DRC, whereby extending the Exploration Permit for a period of ten months to facilitate the drilling of a well on the Lotshi Block (see "Marketing" below).

The Company paid a signing bonus of US$500,000, US$50,000 for geological data and US$250,000 for the Exploration Permit required by the PSC. The first year minimum exploration work commitment was an estimated US$3,500,000 and was surpassed. The minimum work commitment over the remaining period is an estimated total of US$30,000,000. All amounts spent towards the minimum work commitment are subject to review and approval by the Ministry. The PSC provides the following work program guidelines and estimated expenditures for the minimum work commitment:

First Sub-Period (1 year), the estimated exploration expenditure is US$3,500,000 and the work guidelines include:

- Collect all available regional geological data, both seismic data and well data, and complete a study of the Hydrocarbon potential of the License below the Loeme Salt.
- Attempt to purchase at least 250 linear kilometers of 2D seismic.
- Participate in the organization and maintenance of a Data Bank with the General Secretary of Hydrocarbons.
- Create regional structure maps with oil seeps, map potential Hydrocarbon bearing zones using the available 2D seismic, and identify possible drill sites.
- If the existing seismic data quality and interpretation is adequate to justify an exploration well, drill one exploration well.

Second Sub-Period (2 years), the estimated exploration expenditure is US$20,000,000 and the work guidelines include:

- Drill two back to back exploration wells to a minimum depth of 2,000 meters (6,562 feet) to test one or more Hydrocarbon prospects below the Loeme Salt. The second well can be a development well. Bottom hole pressure tests shall be taken for productive reservoirs.
- Acquire at least 250 linear kilometers of 2D seismic data, and integrate with existing 2D seismic data.
- In the last six months of the Second Sub-Period, drill an exploration or development well at the best location and prospect, and if justified (avoid drilling two dryholes), drill a second exploration or development well.

Third Sub-Period (2 years), the estimated exploration expenditure is US$10,000,000 and the work guidelines include:

- Prepare and present a detailed geological and geophysical interpretation of the License, and prepare and present initial plans for the development, production, storage and sale of Hydrocarbons from the License.
- Acquire 500 linear kilometers of 2D seismic.
- Drill a new exploration or development well based upon the updated data, with the option to drill a second development well.

As required by the PSC, the Company is obligated to pay annually US$250,000 to the Ministry for various fees and US$20,000 to the Ministry of Environment.

The Company is also required to allocate US$100,000 annually for the benefit of the local communities situated on the lands of the PSC, for improving their health, education and culture. During the nine months ended November 30, 2015, the Company allocated $nil (nine months ended November 30, 2014 - $110,880 (US$100,000)) and spent $50,249 (US$39,328) (nine months ended November 30, 2014 - $47,757 (US$42,721)). As at November 30, 2015, the Company has spent a total of $390,421 (US$363,551) (February 28, 2015 - $340,103 (US$324,167)) and has an additional $165,768 (US$124,143) (February 28, 2015 - $204,539 (US$163,527)) allocated for social and community spending, the amount of which is classified as restricted cash.

Additionally, the PSC requires the Company to pay a discovery bonus of US$1,000,000 upon the discovery of commercial oil and gas; a production bonus of US$5,000,000 upon the production of 10,000,000 barrels of oil; US$250,000 upon the application and approval of an exploitation permit; US$250,000 upon the execution of the exploitation license; and US$125,000 upon renewal of the exploration license or exploitation license. The agreement is subject to a government royalty of 9% on the first 4 million barrels of production, and 12.5% thereafter.

The Company has constructed two schools and a medical clinic for the local community living on the Lotshi block.

As at November 30, 2015, the Company had incurred total expenditures of $10,368,470 (February 28, 2015 - $10,330,988) on this project. These expenses have not yet been reviewed or approved by the Ministry.

Geological overview

The Lotshi Block covers approximately 507 square kilometers of the "Les Zones du Bassin Côtier" ("ZBC") in the onshore coastal salt basin of western DRC. The Losthi Block is contiguous to the highly prospective Cabinda area of Angola and is on trend with the M'Boundi giant field in Republic of Congo and situated in a similar geological rift graben. The Lotshi Block is also in relatively close proximity to the offshore Cabinda, Malongo and Takula giant field complexes operated by Chevron. Contiguous to the west of the Lotshi Block, in onshore Cabinda, are several undeveloped shallow oil discoveries, in blocks, held by Sonangol and Pluspetrol. The

ZBC also includes the East-Mibale, Laiwenda-Kinkasi and Muana-Banana fields operated by Perenco (approximately 20 miles due southwest from Lotshi Block, producing approximately 15,000 bbls/day). The Lotshi Block is also contiguous to a bitumen mining license on the eastern boundary of the block, where there are known surface oil seeps.

Marketing

The PSC expired on November 1, 2014. On April 3, 2015, the Company received a letter from the Director of the Cabinet of the Prime Minister of the DRC, whereby extending the Exploration Permit for a period of ten months (the "Extension Term") to facilitate the drilling of a well on the Lotshi Block. Negotiations for the renewal of the PSC and Exploration Permit will depend upon the successful completion of the well during the Extension Term. The Company continues in discussions with potential joint venturers to drill on the Lotshi Block.

Historical timeline

- November 2005 - EnerGulf Africa, a wholly owned subsidiary of the Company, is granted the PSC by the Government of the DRC, for the Lotshi Block, containing 507 square kilometers, lying approximately 30 kilometers from the west coast of the DRC. The PSC grants EnerGulf Africa a 90% working interest and COHYDRO a 10% carried working interest.
- March 2008 - Presidential Decree approving PSC.
- July 2008 – New Resolution Geophysics completes aeromagnetic and gravity survey for Lotshi Block.
- February 2009 - EnerGulf Africa and COHYDRO enter into a Contrat D' Association (Joint Operating Agreement) for the Lotshi Block.
- August 2009 – EnerGulf Congo, a subsidiary of the Company, engages Demining Enterprises International (Pty) Ltd ("Demining"), to assess and locate all landmines and other ordinances on the Lotshi Block.
- October 2009 - Issuance of Permis d' Exploration (Exploration Permit) for the Lotshi Block.
- November 2009 – EnerGulf Congo receives the Demining General Landmine / UXO Assessment Report for the Lotshi Block, which identifies two "no go" areas, one immediately across the border into Cabinda Angola, and the other approximately 2.7 kilometers into the northwestern portion of the Lotshi Block.
- November 2009 – Pluspetrol Angola Corporation ("Pluspetrol") commences drilling of the Castanha No. 1 well on the Cabinda South Block, Cabinda Angola, which lies immediately contiguous to the western boundary of the Lotshi Block. The Castanha No. 1 well is completed in the Chela formation with a gross Chela pay interval of over 15 meters and an oil gravity of 33 API. Pluspetrol produces approximately 7,000 barrels of oil per day from 10 active wells by the end of 2013.
- February 2010 - The Company signs contract with The Geophysical Institute of Israel ("GII") to conduct a high quality 2D seismic acquisition program covering more than 200 square kilometers of the Lotshi Block.
- October 2010 – EnerGulf Africa and the Ministry of Hydrocarbons enter into a Memorandum Agreement amending the commencement date of the PSC to October 31, 2009, the date of the Exploration Permit.
- October 2010 - April 2011 - SOCO International PLC ("SOCO") drills three wells on the Nganzi Block on the northern boundary of the Lotshi Block, the Nganga No. 1, the Bayingu No. 1 and the Kinganga Nyanya No. 1, all of which are dryholes. The SOCO wells prove good interbedded source development in the Bucomazi and hydrocarbon generation and migration within the Lemba Trough, but failed due to the lack of a reservoir seal, lack of structural closure, or lack of hydrocarbon presence.
- January 2011 – GII completes 2D seismic acquisition for the Lotshi Block.
- March 2011 – The Company completes its initial mapping of the new 2D seismic and integrating it with the older 2D seismic data, from more than 400 kilometers of 2D seismic data. Developed seven independent drillable prospects for the Company.
- March 2011 – The Company engages D&M, an independent international petroleum consulting firm located in Dallas, Texas (www.demac.com) to prepare an assessment of the Prospective Resources for the Lotshi Block.
- May 2011 – The Company received D&M's Gross Prospective Oil Resources Evaluation for the Lotshi Block.
- September 2013 – The Company engages Moyes & Company (www.moyesco.com) to assist in facilitating a transaction with a strategic co-venturer for the Lotshi Block.
- November 2013 – EnerGulf Africa engages Le Bureau D' Expertise Environnementale OGEC to conduct a pre-drill environmental and social evaluation for the Lotshi Block. The Complement De L'etude D'Impact Environnemental Et Social du Pojet d' exploration – Production des Hydreocarbures dans le Bloc Lotshi is completed in February 2014 and approved for submission to the Ministry of Hydrocarbons in early March 2014.
- January 2014 – EnerGulf Africa updates its geological and geophysical construct for the Lotshi Block to include a basement fan play. EnerGulf Africa obtains Confidentiality Agreements from multiple companies interested in oil and gas exploration in the DRC, and makes multiple presentations in London, UK.

- May 2014 – EnerGulf Africa updates its geological and geophysical construct for the Lotshi Block based upon input from the presentations to include Chela formation prospects, and makes second presentations to qualified partners.
- April 2015 – The Company received a letter of extension granted from the Government of the DRC.

Albanian Hydrocarbon License

On September 29, 2015, through the acquisition of Columbus Copper, the Company acquired the rights to a pending onshore hydrocarbon license under Block 8, Republic of Albania. The license is pending governmental action.

Production Sharing Contract Overview

On July 15, 2015, the Ministry of Energy and Industry of Albania ("Albania") and Albanides Energy SHPK ("Albanides"), entered into a Production Sharing Contract ("ROA PSC") for Block 8, Republic of Albania, covering approximately 3,200 square kilometers. Albanides is a wholly owned subsidiary of EnerGulf. The ROA PSC First Exploration Period term is three years, with a Minimum Work Program consisting of Geological and Geophysical work, a gravity survey, and Health Safety and Environmental studies, and a total minimum expenditure of US$1,400,000. The ROA PSC Second Exploration Period is two years, with a Minimum Work Program consisting of Geological and Geophysical work, and 2D seismic acquisition (150 km), and a total minimum expenditure of US$1,800,000. The ROA PSC Third Exploration Period is two years, with a Minimum Work Program consisting of Geological and Geophysical and an Exploration Well to a depth of 2,000 meters, and a total minimum expenditure of US$2,100,000. Each subsequent Exploration Period is dependent upon performance in the preceding Exploration Period. In the event the Minimum Work Program costs less than the total minimum expenditure for the Exploration Period, Albanides must pay Albania the difference of the actual expenditures and the total minimum expenditures. Field discoveries are granted development and production periods of twenty years, with five year extension options. The royalty tax is 10%. Profit Petroleum (Oil – 0% – 3% or Gas – 0% – 7.5%) is shared on a sliding scale based upon cost recovery. Realized Profit to the Contractor is taxed at 50%. The ROA PSC contains customary provisions for training and administration, local hiring, customs exemptions, export rights, environmental protection, bonus payments, notices, definitions and other matters. The ROA PSC is pending final government approval and publication.

Geological Overview

Northern Albania consists of a complex nappe stack with a polyphase tectonic history. Two models exist to explain the origin of the different units.

Model A sees the Mirdita ophiolites as remnant of an autochthonous ocean (Pindos-Mirdita Ocean) flanked by two passive margins formed during Late Triassic to Middle Jurassic. The western margin corresponds according to this model to the External Albanides and the eastern margin corresponds to the Internal Albanides (Korabi-Pelagonia). This ocean should start to close since Middle Jurassic by remained open until the late Palaeogene/early Neogene. During that time, the ocean finally was closed and flysch basins were formed since the Palaeogene. Therefore, the nappe stack is west directed in the External Zones and east directed in the Internal zones, were the ophiolites were thrust over Korabi-Pelagonia in eastward directions.

Model B sees the ophiolites as far-travelled nappes coming from the east. Therefore, the ophiolites came from the Neotethys Ocean, which starts to form in the Middle Triassic and thrust over the Korabi-Pelagonian Zone in Middle to Late Jurassic times. All Triassic to Middle Jurassic sequences are seen as one passive continental margin facing the Neotethys Ocean to the east. During westward thrusting of the ophiolites (obduction) the Triassic-Jurassic sedimentary sequences form – in plate tectonic view – the lower plate and a west-vergent fold-and-thrust-belt was built with deep-water, partly restricted basins in front of the propagating thrust belt. Latest Jurassic to Cretaceous sediments were deposited as neoautochthonous cover on top of the Jurassic nappe stack. Ongoing tectonic movements (e.g. uplift and extension of the nappe pile with westdirected normal faults) in Cretaceous times and final closure of the Neotethys Ocean (Vardar) in the east forms in Palaeogene to Neogene times the actual nappe stack. These youngest mountainbuilding processes led to west directed thrusting with formation of foreland basins in the External Albanides and east directed backthrusting in the Internal Albanides, again with formation of new foreland basins.

Albanian Chromite License

On September 29, 2015, the Company acquired two exploration licenses and an operations license in the Republic of Albania, through the acquisition of Columbus Copper. The exploration licenses are referred to as Bulqiza, and the Qafe Burreli being the operations license. The licenses cover approximately 6.8 km^2 of the chromite-bearing, Bulqiza ultramafic massif in eastern Albania. Columbus Copper was originally awarded these licenses on January 29, 2009.

On December 22, 2010, Columbus Copper completed a 3% royalty and share sale with the Anglo-Pacific Group ("APG"). In connection with the royalty sale, Columbus Copper executed a security agreement and has pledged to APG the securities of its 100% owned BVI subsidiary, Empire International Mining Corporation, and its 100% owned Albanian subsidiary, Empire Mining (Albania) SHPK.

Exploration and evaluation expenses incurred on the Company's properties for the nine months ended November 30, 2015 and 2014 are as follows:

	Namibia	Democratic Republic of Congo	Albanian Hydro Carbon Licenses	Total
Expenditures to date, March 1, 2014	12,543,220	9,847,205	-	22,390,425
Acquisition	-	343,971	-	343,971
General and administration	32,919	42,281	-	75,200
Geological	-	65,290	-	65,290
Expenditures to date, November 30, 2014	12,576,139	10,298,747	-	22,874,886
Expenditures to date, March 1, 2015	12,586,268	10,330,988	-	22,917,256
Acquisition	-	-	254,275	254,275
General and administration	12,288	37,482	-	49,770
Consulting	(75,263)	-	-	(75,263)
Expenditures to date, November 30, 2015	**12,523,293**	**10,368,470**	**254,275**	**23,146,038**

Selected financial information

The following table presents selected financial data for each of the last eight quarters, derived from the Company's consolidated financial statements.

	Q3 2016 ($)	Q2 2016 ($)	Q1 2016 ($)	Q4 2015 ($)	Q3 2015 ($)	Q2 2015 ($)	Q1 2015 ($)	Q4 2014 ($)
Net loss for the period	(413,013)	(162,094)	(209,519)	(301,260)	(530,978)	(324,466)	(670,484)	(509,172)
Basic and diluted loss per share	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)

	Nov 30, 2015 ($)	Aug 31, 2015 ($)	May 31, 2015 ($)	Feb 28, 2015 ($)	Nov 30, 2014 ($)	Aug 31, 2014 ($)	May 31, 2014 ($)	Feb 28, 2014 ($)
Cash	87,060	7,933	48,445	107,976	53,230	149,039	450,207	936,791
Restricted cash	165,768	163,335	203,767	204,539	214,807	196,470	202,127	150,843
Total assets	465,764	368,727	416,149	496,556	475,668	560,056	852,176	1,309,713

Three months ended November 30, 2015, compared with three months ended November 30, 2014

The Company's net loss for the three months ended November 30, 2015 was $413,013, compared to $530,978 during the same period in the prior year. Total operating expenses for the current quarter were $381,563 compared to $515,186 for the prior year quarter. Significant variations are described below.

General exploration expense this quarter was $186,264, compared to $255,998 during the same period in the prior year. General exploration expense in the current quarter is primarily a result of the acquisition of Columbus Copper, offset by a recovery of $75,263 in consulting, whereas the prior year quarter amount reflects the level of general exploration activity conducted by the Company.

Management fees include the compensation costs of the Company's officers. Management fees amounted to $21,682 this quarter (2014 - $46,058), a decrease of $24,376.

Professional fees during the current quarter totalled $72,827, compared to $22,411. The increase is primarily attributable to legal fees associated with the acquisition of Columbus Copper in the amount of $34,038.

Nine months ended November 30, 2015, compared with nine months ended November 30, 2014

The Company's loss for the nine months ended November 30, 2015 was $784,626, compared to $1,525,928 during the prior year period. Total operating expenses for the current period was $769,205 compared to $1,507,930 for the prior year period. Significant variations are described below.

General exploration expense this period was $228,782, compared to $484,461 during the same period in the prior year. General exploration expense in the current period is primarily a result of the acquisition of Columbus Copper, offset by a recovery of $75,263 in consulting, whereas the prior year period amount reflects the level of general exploration activity conducted by the Company.

Management fees include the compensation costs of the Company's officers. Management fees amounted to $98,768 this period (2014 - $145,363), a decrease of $46,595.

Office and administration expenses are costs related to operating and administering the company offices and corporate finance activities. Office and administration expenses amounted to $156,367 this period, compared to $237,301 during the prior year period. The decrease in the current period is primarily attributable to the Company'scost savings measures.

Professional fees during the current period totalled $120,677, compared to $79,446. The increase is primarily attributable to legal fees associated with the acquisition of Columbus Copper in the amount of $34,038.

Share-based payments expenses included in loss are a non-cash accounting entry and include all share-based awards such as stock options granted to employees, non-employees, directors, officers, employees and consultants. The awards are measured and recognized using a fair value based method in accordance with the IFRS 2. The value of share-based payments this period totaled $15,028, compared to $336,595 during the prior year period. These compensation expenses were calculated using the Black-Scholes fair value option pricing model.

Travel expenses consist of transportation, lodging, and meals of directors, officers and consultants. Travel costs were $6,522 this period, compared to $74,818 during the prior year period, a decrease of $68,296 due to limited travel required on the various projects.

Liquidity and capital resources

As at November 30, 2015, the Company had cash of $87,060 (February 28, 2015 - $107,976) and marketable securities of $nil (February 28, 2015 – $6,154).

During the three and nine months ended November 30, 2015, the Company expended cash of $99,587 and $278,478, respectively, (2014 – $350,401 and $1,093,062, respectively) on operating activities. Cash used in operations consist of cash used to fund the loss for the period less the impact of non-cash items, and the cash used for working capital purposes.

During the three and nine months ended November 30, 2015, the Company had cash inflows of $206,116 from the acquisition of Columbus Copper. Amounts deposited to or withdrawn from *Restricted cash* are for social and community spending in DRC.

During the current quarter, the Company repaid a loan of $27,423 (US$22,000) to a corporation, of which a shareholder of the Company is principal. During the three and nine months ended November 30, 2014, the Company received loan proceeds of $112,750, offset by repayments of $55,615, and received $207,269 for a planned private placement offering.

The Company has a working capital deficit of $965,636 at November 30, 2015 (February 28, 2015 – $623,978) and a deficit of $45,448,967 (February 28, 2015 - $47,153,061). The Company considers the Chromite License in the Republic of Albania to be a non-core asset, and intends to sell the Chromite License and raise equity funds to meet its short-term and ongoing exploration activities. The Company will review all assets and may liquidate some assets which are inconsistent with the capital position of the Company in order to raise equity funds to maximize value in the remaining assets.

Off-balance sheet arrangements

The Company has no off-balance sheet arrangements.

Related party transactions

The following related party transactions were in the normal course of operations and are measured at their exchange amounts being the amount of consideration as agreed to between the parties and consists of the following items:

	Three months ended		Nine months ended	
	November 30, 2015 ($)	November 30, 2014 ($)	November 30, 2015 ($)	November 30, 2014 ($)
Consulting fees paid or accrued to Resource Finance Ltd., a Company owned by Jeff Greenblum	1,500	1,500	4,500	4,500
Management fees paid or accrued to John D. Elmore	21,682	18,457	63,144	56,211
Fees paid or accrued to Marrelli Support Services Inc. ("Marrelli") for CFO and accounting services	-	10,865	28,316	39,034
Fees paid or accrued to DSA Corporate Services Inc. ("DSA"), an affiliate of Marrelli, for corporate secretarial and filing services	1,413	3,900	12,041	12,450
	24,595	**34,722**	**108,001**	**112,195**

The following balances remain payable as at each reporting date:

	November 30, 2015 ($)	February 28, 2015 ($)
John D. Elmore	105,065	34,397
Jeff Greenblum	17,126	7,535
Peter Gianulis	10,502	-
Resource Finance Ltd.	260,204	261,312
Marrelli	20,912	15,389
DSA	-	4,709
	413,809	**323,342**

Commitments

The Company has no commitments at the date of this MD&A and as at November 30, 2015.

Proposed transactions

There are no proposed transactions as at the date of this MD&A and as at November 30, 2015.

Critical accounting estimates

The preparation of financial statements requires the Company to select from possible alternative accounting principles, and to make estimates and assumptions that determine the reported amounts of assets and liabilities at the balance sheet date and reported costs and expenditures during the reporting period. Estimates and assumptions may be revised as new information is obtained, and are subject to change. The Company's accounting policies and estimates used in the preparation of the consolidated financial statements are considered appropriate in the circumstances, but are subject to judgments and uncertainties inherent in the financial reporting process. Exploration and evaluation costs, including acquisition costs of oil and gas properties and exploration and evaluation activities, are charged to earnings as they are incurred until the property has been established as technically feasible and commercially viable, at which point related development expenditures are capitalized. The technical feasibility and commercial viability of extracting oil and gas resource from exploration and evaluation assets is considered to be generally determinable when proved and probable reserves are determined to exist.

The Company's current market price and the volatility of the Company's market price will affect the estimates made for share-based payments. The volatility of the Company's stock price and the stock price at the grant date have the most significant impact on the estimate of fair value of share-based payments. The Company expenses share-based payments for its employees whose options vest immediately at grant. For employees, whose options vest over time, the Company amortizes the fair value over the vesting period.

Share-based payments are accounted for using the fair value based method. Under the fair value based method, compensation cost is measured at fair value of the options at the date of grant and is expensed over the vesting period of the award. The Company estimates the fair value using the Black-Scholes option pricing model.

The Company operates in several jurisdictions and it estimates taxes in each jurisdiction taking into consideration different tax rates, non-deductible expenses, valuation allowances, changes in tax laws and expectations for future results.

The Company bases its estimates of future income taxes on temporary differences between the assets and liabilities reported in the financial statements, and the assets and liabilities determined by the tax laws in the various countries it operates in.

Changes in accounting policies and standards

A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended November 30, 2015, and have not been applied in preparing these consolidated financial statements. Those that may have a significant effect on the consolidated financial statements of the Company are as follows:

(a) IFRS 9 – *Financial instruments* ("IFRS 9")

This new standard is a partial replacement of IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. IFRS 9 is effective for annual periods beginning on or after January 1, 2018.

(b) Other

Other accounting standards or amendments to existing accounting standards that have been issued but have future effective dates are either not applicable or are not expected to have a significant impact on the Company's financial statements.

Financial instruments

The fair value of the Company's financial instruments, financial statement classification and associated risks are presented in the table below:

Financial instrument	**Financial statement classification**	**Associated risks**	**Fair value at November 30, 2015 ($)**
Cash	Carrying value	Credit, currency and concentration	87,060
Restricted cash	Carrying value	Credit, currency and concentration	165,768
Amounts receivable	Carrying value	Credit and concentration	20,218
Security deposits	Carrying value	Credit, currency and concentration	63,064
Accounts payable and accrued liabilities	Carrying value	Currency	(1,071,722)
Due to related parties	Carrying value	n/a	(260,204)
Promissory note payable	Carrying value	Interest	(20,912)
			(1,016,728)

IFRS 7, *Financial Instruments: Disclosure* establishes a fair value hierarchy that prioritizes the input to valuation techniques used to measure fair value as follows:

Level 1 – quoted prices (unadjusted) in active markets for identical assets or liabilities;
Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices); and
Level 3 – inputs for the asset or liability that are not based on observable market data (unobservable inputs).

As at November 30, 2015, the Company does not have any financial instruments that require valuation techniques to measure fair value.

The Company manages its exposure to financial risks, including credit risk, liquidity risk, currency risk, interest rate risk and price risk in accordance with systems put in place to manage these risks, as monitored by the board of directors (the "Board"). The Board approves and monitors the risk management processes and there were no changes to the objectives or the process from the prior year. Please refer to the "Risks and uncertainties" section in this report for a full description of the types of risks that the Company is exposed to and its objectives and policies for managing those risk exposures.

Other information

Outstanding share data

At the date of this MD&A, the Company had 92,597,725 common shares issued and outstanding. In addition, there were 4,690,000 share purchase options outstanding with exercise prices ranging from $0.18 to $0.66 per share, and 2,853,164 warrants outstanding with exercise price of $0.25 per share.

Disclosure and internal controls

Disclosure controls and procedures have been established to provide reasonable assurance that material information relating to the Company is made known to management, particularly during the period in which annual filings are being prepared. Furthermore, internal controls have been established to ensure the Company's assets are safeguarded and to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with IFRS.

There have been no material changes in the Company's internal controls during the nine months ended November 30, 2105.

Risks and uncertainties

The Company continues its emphasis on oil and gas exploration with a view to discover reserves and generate cash flows and is reviewing other projects of interest as they come available. The oil and gas business is subject to a number of risks and other factors which may have an impact on the Company, including but not limited to the following:

Overseas projects

The Company's projects are located in foreign jurisdictions and are subject to risks relating to political stability and changes in laws relating to foreign ownership, government participation, taxation, royalties, duties, rates of exchange, exchange controls, restrictions on production, export controls, land use and operational safety, and the potential for terrorism or military repression. Because a significant percentage of its operating costs, exploration expenditures and lease maintenance and acquisition costs are denominated in U.S. dollars, the Company's results of operations are subject to the effects of fluctuations in exchange rates and inflation. The Company does not engage in any hedging activities to minimize such risks.

Exploration and production risks

Drilling oil and gas wells involves the risk that the wells will be unproductive or that, although productive, the wells do not produce oil and/or gas in economic quantities. Other hazards, such as unusual or unexpected geological formations, pressures, fires, blowouts, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well. Adverse weather conditions can also hinder drilling operations. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is impregnated with water or other deleterious substances. As with any petroleum property, there can be no assurance that oil and gas will be produced from the properties in which the Company has interests. In addition, the marketability of oil and gas, which may be acquired or discovered, will be affected by numerous factors beyond the control of the Company. These factors include the proximity and capacity of oil and gas pipelines and processing equipment, market fluctuations of prices, taxes, royalties, land tenure, allowable production and environmental protection. The extent of these factors cannot be accurately predicted, but the combination of these factors may result in the Company not receiving an adequate return on invested capital. There is no assurance that additional crude oil or natural gas in commercial quantities will be discovered by the Company.

Financing risks

The Company has primarily relied on the sale of its equity capital to fund the acquisition, exploration and development of its petroleum properties. It has no assurance that additional funding will be available to it for exploration and development of its projects or to fulfill its obligations under any applicable agreements. There can be no assurance that the Company will be able to generate sufficient operating cash flow or obtain adequate financing in the future or that the terms of such financing will be favourable. Failure to generate such additional operating cash flow or obtain such additional financing could result in delay or indefinite postponement of further exploration and development of its projects with the risk of possible loss of such properties.

Natural gas and oil prices

In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and, to a lesser extent, natural gas. The excess or short supply of crude oil and natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand.

No history of earnings

EnerGulf has no history of earnings or of a return on investment, and there is no assurance that any of its properties will generate earnings, operate profitably or provide a return on investment in the future. The Company has not paid dividends in the past and has no plans to pay dividends for some time in the future. Its board of directors will determine the future dividend policy of EnerGulf. Some of the Company's oil and gas interests may consist of oil and gas tenures which have not been surveyed, and therefore, the future determination of those interests, the precise area and location of such interests may be in doubt. Although there are resources estimates, there are no known reserves of oil and gas on EnerGulf's properties.

Repatriation of earnings

Regulations of foreign countries may provide that subject to payment of applicable taxes, foreign investors may remit out of those countries, in foreign exchange, profits or dividends derived from a source within those countries. Remittance by foreign investors of any other amounts (including for instance, proceeds of sale arising from a disposal by a foreign investor of any of his investment in those countries) out of those countries may be subject to the approval of the respective State administrations. No assurance can be given that such approval would be granted. Further, there can be no assurance that additional restrictions on the repatriation of earnings in those countries will not be imposed in the future.

Political investment risk; political instability in developing countries

EnerGulf's interests are in countries that may be affected by varying degrees of political instability and the policies of other nations in respect of these countries. These risks and uncertainties include military repression, political and labour unrest, extreme fluctuations in currency exchange rates, high rates of inflation, terrorism, hostage taking and expropriation. EnerGulf's current projects are located in Southern and West Africa, in the countries of Namibia and Democratic Republic of Congo. EnerGulf's exploration and development activities may be affected by political instability and the nature of various government regulations relating to the oil and gas industry. Any changes in regulations or shifts in political conditions are beyond the control of EnerGulf and may adversely affect its business and/or its holdings.

Operations may be affected in varying degrees by government regulations with respect to restrictions on production, price controls, export controls, income taxes, expropriation of property, environmental legislation and safety factors. EnerGulf's operations in those countries entail significant governmental, economic, social, medical and other risk factors common to all developing countries. See

"Economic Uncertainty in Developing Countries". The status of these countries as developing countries may make it more difficult for EnerGulf to obtain any required financing because of the investment risks associated with these countries.

Economic uncertainty in developing countries

EnerGulf's future operations may be adversely affected by economic uncertainty characteristic of developing countries. For example, some countries have experienced high rates of inflation for many years. There can be no assurance that any governmental action to control inflationary or deflationary situations will be effective in ensuring economic stability or that future governmental action will not trigger inflationary or deflationary cycles. Additionally, changes in inflation or deflation rates and governmental actions taken in response to such changes can also affect currency values in such countries. Any such changes could have a material adverse effect on EnerGulf's results of operations and financial condition. While these countries permit private economic activities, the governments have exercised and continue to exercise substantial control over virtually every sector of their economy through regulation and state ownership. EnerGulf's prospects, results of operations and financial condition may be adversely affected by political, economic and social uncertainties, changes in leadership, diplomatic developments and changes or lack of certainty in the laws and regulations of these countries.

Current resource exploration conditions

The current infrastructure in these countries may not be adequate to support EnerGulf's planned activities. For example, the continued reliability, or the ability of the appropriate authorities to maintain water supply, electricity supply and transportation accessibility is presently undetermined or being studied. In addition, there are technical risks associated with oil and gas exploration. These risks could result in increased operating costs.

Title risks

The acquisition of title to oil and gas properties or interests therein is a very detailed and time-consuming process. Title to and the area of resource concessions may be disputed. EnerGulf will however, before expending funds on exploration and drilling activities, make efforts to ensure that title is secure.

Currency fluctuations

Presently, the Company's hydrocarbon exploration activities are conducted in Africa and all petroleum revenues and expenditures are conducted in both United States and Canadian dollars. To date, all equity financings transacted by the Company have been conducted in Canadian dollars. The Company will maintain certain of its cash holdings in United States dollars. Future fluctuations in the value of the Canadian relative to the US dollar may have a material and adverse effect on the Company's ability to conduct financings in the future.

Management's responsibility for financial statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying consolidated financial statements.

Approval

The Board of Directors oversees management's responsibility for financial reporting and internal control systems through an Audit Committee. This Committee meets periodically with management and annually with the independent auditors to review the scope and results of the annual audit and to review the consolidated financial statements and related financial reporting and internal control matters before the financial statements are approved by the Board of Directors and submitted to the shareholders of the Company. The Board of Directors of the Company has approved the consolidated financial statements and the disclosure contained in this MD&A. A copy of this MD&A will be provided to any shareholder who requests it.

Caution regarding forward looking statements

This document contains certain forward-looking information and forward-looking statements, as defined in applicable securities laws (collectively referred to as "forward-looking statements"). Often, but not always, forward-looking statements can be identified by the use of words such as "plans," "expects" or "does not expect," "is expected," "planned," "budget," "scheduled," "estimates," "continues," "forecasts," "projects," "predicts," "intends," "anticipates" or "does not anticipate," or "believes," or variations of such words and phrases, or statements that certain actions, events or results "may," "could," "would," "should," "might" or "will" be taken, occur or be achieved. Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause the Company's actual results, performance or achievements to be materially different from any of the Company's future results, performance or achievements expressed or implied by the forward-looking statements; consequently, undue reliance should not be placed on forward-looking statements.

These risks, uncertainties and other factors include, but are not limited to: changes in Canadian/US dollar exchange rates; the Company's strategies and objectives; the Company's tax position and the tax and applicable royalty rates; the Company's ability to acquire necessary permits and other authorizations in connection with its projects; risks associated with environmental compliance, including without limitation changes in legislation and regulation, and estimates of reclamation and other costs; the Company's cost reduction and other financial and operating objectives; the Company's environmental, health and safety initiatives; the availability of qualified employees and labour for operations; risks that may affect operating or capital plans; risks created through competition for oil and gas properties; risks associated with exploration projects, and oil and gas reserve and resource estimates, including the risk of errors in assumptions and methodologies; risks associated with dependence on third parties for the provision of critical services; risks associated with non-performance by contractual counterparties; risks associated with title; and general business and economic conditions.

Forward-looking statements are based on a number of assumptions that may prove to be incorrect, including, but not limited to, assumptions about: general business and economic conditions; the timing of the receipt of required approvals for operations; the availability of equity and other financing on reasonable terms; power prices; ability to procure equipment and operating supplies in sufficient quantities and on a timely basis; ability to attract and retain skilled labour and staff; the impact of changes in Canadian/US dollar and other foreign exchange rates on costs and results; market competition; and ongoing relations with employees and with business partners and joint venturers.

Management cautions the reader that the foregoing list of important factors and assumptions is not exhaustive. Events or circumstances could cause actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. Management undertakes no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing list of factors, whether as a result of new information or future events or otherwise, except as may be required under applicable laws.

Other information

Additional information relating to the Company is available on SEDAR at www.sedar.com.

Corporate information

Head Office:	1090 Hamilton Street Vancouver, BC V6B 2R9
Directors:	Jeff Greenblum John Elmore Peter Gianulis Robert Giustra
Officers:	John Elmore, President Akbar Hassanally, Chief Financial Officer Jenna Virk, Vice President, Legal and Corporate Secretary Jorge Martinez, Vice President, Communication and Technology
Auditor:	DMCL LLP 1150 – 1140 West Pender Street Vancouver, BC V6E 4G1
Legal Counsel:	McMillan LLP Suite 1500 - 1055 West Georgia Street Vancouver, BC V6E 4N7
Transfer Agent:	Computershare Investor Services 2nd Floor – 510 Burrard Street Vancouver, BC V6C 3B9