Genel Energy PLC (GENL)

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6 August 2019

Genel Energy plc
Unaudited results for the period ended 30 June 2019

Genel Energy plc ('Genel' or 'the Company') announces its unaudited results for the six months ended 30 June 2019.

Bill Higgs, Chief Executive of Genel, said:
"These results demonstrate the continued success of our strategy - highly cash generative production underpins capital investment in growth opportunities that deliver rapid returns and enables a compelling cash return to shareholders through our dividend.

Our production grew 17% in H1 2019, and pro forma free cash flow rose to $76 million. This cash generation, and our strong balance sheet, allows us to both increase investment in growing the business as well as returning cash to shareholders via dividends. Accordingly, we have today announced an interim dividend of $14 million.

Disciplined capital allocation remains at the core of our business. The speed with which our investments pay back means that cash is quickly recycled to create most value for shareholders. The cash that our production generates funds work now underway at Sarta and Qara Dagh, with plenty left over to both pay a dividend and seek new opportunities, as we progress Genel's growth strategy."

Results summary ($ million unless stated)

	H1 2019	*H1 2018*	*FY 2018*
Production (bopd, working interest)	**37,400**	*32,100*	*33,700*
Revenue	**194.3**	*161.1*	*355.1*
EBITDAX[1]	**167.3**	*137.4*	*304.1*
Depreciation and amortisation	**(74.8)**	*(63.6)*	*(136.2)*
Exploration (expense) / credit	**(0.6)**	*(0.5)*	*1.5*
Impairment of intangible assets	**-**	*-*	*(424.0)*
Operating profit / (loss)	**91.9**	*73.3*	*(254.6)*
Cash flow from operating activities	**142.3**	*125.1*	*299.2*
Capital expenditure	**72.2**	*34.1*	*95.5*
Free cash flow[2]	**56.7**	*70.1*	*164.2*
Pro forma free cash flow[2]	**75.6**	*70.1*	*164.2*
Dividend payments	**27.4**	*-*	*-*
Cash[3]	**353.3**	*233.2*	*334.3*
Total debt	**300.0**	*300.0*	*300.0*
Net cash (debt)[4]	**55.8**	*(63.8)*	*37.0*
Basic EPS (¢ per share)	**27.2**	*21.3*	*(101.6)*
Underlying EPS (¢ per share)[1]	**59.9**	*49.2*	*109.0*

1. EBITDAX is operating profit / (loss) adjusted for the add back of depreciation and amortisation ($74.8 million) and exploration expense ($0.6 million). Underlying EPS is EBITDAX divided by the weighted average number of ordinary shares
2. Free cash flow is set out on page 7 and does not include $18.9 million, invoiced for Tawke production and due in June 2019 and received late on 9 July 2019, with the delay due to a change in the Operator's banking arrangements. Pro forma free cash flow of $75.6 million includes this payment.
3. Cash reported at 30 June 2019 excludes $10 million of restricted cash and the $18.9 million noted above
4. Reported IFRS debt less cash

Highlights

- Working interest production averaged 37,400 bopd in H1 2019 (H1 2018: 32,100 bopd), an increase of 17% compared to H1 2018
  - 8 wells completed in H1 2019, resulting in year-on-year production increases at both the Tawke and Taq Taq PSCs
- Free cash generation of $57 million in H1 2019 (H1 2018: $70 million), which increases to $76 million when including the post period receipt of $19 million, with annual free cash flow yield of c.20% of current market capitalisation
- Net cash of $56 million at 30 June 2019 (net debt of $64 million at 30 June 2018)
  - Following the receipt of all payments relating to April 2019, Genel had $390 million of cash as of 5 August 2019, a net cash position of $92 million
- Addition of Sarta and Qara Dagh to the portfolio in January 2019 provides near-term production and material future growth potential
- Maiden dividend distribution of 10¢ per share paid on 24 June 2019
- Interim dividend of 5¢ per share confirmed
- Genel retains an open mandate for a share buy-back programme of up to $10 million, and will continue to review purchasing opportunities

Outlook

- Net production guidance in 2019 maintained at close to Q4 2018 levels of 36,900 bopd, an increase of c.10% year-on-year

- Drilling programme ongoing, with over 10 wells set to be completed by early 2020
- Active discussions with the Kurdistan Regional Government ('KRG') regarding Bina Bawi are ongoing, focused on agreeing the detailed commercial terms for the integrated Phase 1 oil and gas development and approval of the associated field development plans
- Work continuing at Sarta to prepare for production by the middle of 2020
- QD-2 well location agreed at Qara Dagh, well pad civil engineering work set to begin
- Farm-out process relating to Somaliland acreage to begin in late Q3 2019
- Genel expects to generate material free cash flow in H2 2019, even while investment in growth increases
    - 2019 capital expenditure is expected to be towards the top end of the $150-170 million guidance range
- Searches for a new Chairman and Chief Operating Officer are progressing
- The Company continues to actively pursue growth and is assessing opportunities to make value-accretive additions to the portfolio

For further information, please contact:

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There will be a presentation for analysts and investors today at 0930 BST, with an associated webcast available on the Company's website, www.genelenergy.com.

This announcement includes inside information.

CEO STATEMENT

Genel aims to be a world-class creator of shareholder value by growing high-margin production through rapid development and an efficient use of capital, recycling cash flows into an expanding asset portfolio with the potential to deliver significant growth, while generating sufficient cash throughout the investment cycle to fund a material and progressive dividend.

GENERATING CASH WHILE INVESTING IN GROWTH

The oil we produce is good quality, low-cost, and highly cash generative, with a development model focused on optimising cost and minimising development risk. This makes our business highly cash generative. Setting us apart from the majority of our peers both within the region and outside, we have been able to materially increase production without significant cash out - in fact our asset portfolio generates material free cash flow even while increasing production.

This is best illustrated by the Tawke PSC, where production at Peshkabir has increased from 12,000 bopd at the end of 2017 to over 55,000 bopd. While doing so Peshkabir continues to generate material free cash flow, adding $32 million in the first half of 2019. Overall, capital expenditure in the first half of $72 million has nearly doubled from last year, but still free cash flow increased year-on-year.

Our low-cost production also makes us resilient to oil price fluctuations, and we generate cash at a low oil price. As an illustration, even if the Brent oil price averaged $36/bbl in 2019 we would still generate sufficient cash to pay our dividend of $40 million from free cash flow.

The level and speed of our cash generation allows us the optionality to recycle capital into those areas that promise to create the maximum shareholder value. The priority remains investing in our current producing assets to underpin this cash generation, and subsequently spending is now set to ramp up at Sarta and Qara Dagh.

Commercial discussions continue on Bina Bawi, and we are increasingly confident of making sufficient progress to enable work on the ground to begin next year, with the potential for Bina Bawi oil to also add to our production in 2020. And we will continue to generate free cash flow even after making these investments in growth.

A MATERIAL AND PROGRESSIVE DIVIDEND

With our strong cash generation, even while investing in growth and adding assets to the portfolio, paying a dividend was the ultimate intended outcome of our strategy. With our portfolio having the potential to double production in coming years, and an M&A strategy focused on boosting near-term cash generation, we see the baseline annual distribution of $40 million as having the potential to grow on an annual basis.

FOCUS ON ESG

ESG continues to be a key focus of Genel, and we are committed to acting as a socially responsible contributor to the global energy mix. On the environmental side, we aim to minimise GHG emissions per barrel across the portfolio. Working with DNO at Peshkabir, the reinjection of gas into the Tawke field will eliminate routine flaring while having the added bonus of a positive return on investment - another financial benefit that sets us apart from some of our peers.

As work progresses on Sarta, we will keep emissions to a minimum ahead of initiating a flares out programme in due course, and further our social investment work. Previously this work has centred on the area surrounding Taq Taq through work focusing on the environment, health, education, and economic empowerment, and initiatives are set to get under way around Sarta and Qara Dagh. Genel will continue to strive to ensure that the local community benefits from the work we do in their community.

OPERATING REVIEW

PRODUCING ASSETS

Working interest production in H1 2019 averaged 37,400 bopd, a rise of 17% year-on-year.

(by PSC in bopd)	Export via pipeline	Refinery sales	Total sales	Total production[1]	Genel net production
Tawke (inc. Peshkabir)	127,070	-	127,070	126,650	31,660
Taq Taq	13,135	-	13,135	13,150	5,785
Total	**140,205**	**-**	**140,205**	**139,800**	**37,445**

[1] Difference between production and sales relates to inventory movements

All sales during the period were invoiced at the wellhead export netback price.

Tawke PSC (25% working interest)
Production from the Tawke PSC averaged 126,650 bopd, an increase of 20% year-on-year and 12% on the FY 2018 figure. This performance was the result of the success of Peshkabir, where production averaged 54,950 bopd. Production from the Tawke PSC continues to be highly cash-generative, contributing $87 million in free cash flow at an asset level.

The underlying well stock at the Tawke field has produced in line with expectations. Drilling is required to offset natural field decline, and three wells came onto production in the period. T-52 came on stream in mid-February, and T-54 in April, and the two wells have averaged c.3,500 bopd in combined additional production. The T-55 well began adding to production in June and will be followed by a further four confirmed cretaceous producers, while the T-57 well will test the Jurassic potential at Tawke. The field partners will also drill a programme of shallower Jeribe wells.

Peshkabir continues to perform well, with success at both the P-9 and P-10 wells helping increase production. Surface facility work has also been completed, and production from the P-2 and P-3 wells is now flowing through the 50,000 bopd central processing facility. Trucking activity is set to be eliminated following the commissioning of the 60,000 bopd pipeline to Fishkabour, helping to reduce costs from an already low base.

The P-11 well is nearing completion, and three more wells are scheduled to spud in 2019. Work on the enhanced oil recovery project wherein gas is piped from Peshkabir to be injected into the Tawke reservoir, both eliminating flaring and increasing recovery rates, is now underway and is expected to be commissioned in H1 2020.

Taq Taq (44% working interest, joint operator)
Drilling on the flanks at Taq Taq continued to bear fruit in H1, and helped production at the field average 13,150 bopd in H1 2019, an increase of 3% year-on-year and 6% on the FY 2018 figure. The TT-32 well completed in January on the northern flank of the field with an initial flow rate of c.3,000 bopd. This was followed by the TT-20z well, on the western flank, which entered production at a rate of 2,000 bopd. Both wells have recently seen a decline in production and are now in line with Genel's expectations, having been choked back to control water production.

The TT-33 well, on the southern flank, has tested water from three zones, and has not flowed oil at any significant rate, demonstrating that the free water level on the southern flank is higher than to the north. Going forward, the field partners will continue to target the flanks of the field, with a focus on horizontal wells to delay water production and maximise recovery. Wells continue to provide a positive return on investment, and Taq Taq generated $8.4 million of free cash flow in H1 2019. Two horizontal wells are scheduled to be drilled on the northern flank of the field in the second half of the year, and the TT-19x well is currently underway. Drilling in the second half of the year aims to deliver year-on-year production growth.

PRE-PRODUCTION ASSETS

Sarta (30% working interest)
To date, four exploration wells at Sarta have discovered hydrocarbons at multiple intervals, from the Tertiary down to the Triassic. This contributes to the Company's unrisked P50 gross resource estimate of c.500 MMbbls. Phase 1A represents a low-cost development of the Jurasssic Mus-Adaiyah reservoirs. This phase is designed to recover 2P gross reserves of 34 MMbbls through two existing wells (Sarta-2 and Sarta-3) both of which flowed at c.7,500 bopd on test, and one additional development well to be drilled in 2021. Insights from production behaviour during this first phase, combined with an appraisal and development well campaign planned for 2021, will provide the technical foundation for prudent expansion investment decisions aimed at maturing Sarta into a low cost, long-life, cash generative asset.

Construction work for the Phase 1A development is already underway. Civil engineering work commenced in May ahead of mobilising the facility and flowline contractors to the field. Production remains on track to begin in the middle of 2020.

Qara Dagh (40% working interest, operator)
The Qara Dagh prospect was first tested by the vertical exploration well QD-1 in 2011. The reservoir was encountered much deeper than prognosed and operational issues meant the well was significantly overbalance when drilling the reservoir, in so doing damaging the reservoirs ability to flow hydrocarbons. Despite these setbacks QD-1 still tested a light oil from Cretaceous fractured carbonates.

Re-evaluation of the structural model post QD-1, based on new 2D seismic combined with fieldwork, indicates that the well was drilled on the south-eastern flank of the prospect. The location for the second exploration well, QD-2, has been chosen to test the structural crest c.10 km to the NW of where QD-1 flowed oil to surface. QD-2 will be drilled with a deviated trajectory through the same reservoir tested by QD-1 in order to maximise fracture intersection. Managed pressure drilling is being considered to minimise reservoir damage. Genel has undertaken a baseline Environmental, Social and Health Impact Assessment study and will commence construction work on the well pad and associated camp shortly. The QD-2 well is on track to spud in H1 2020.

Bina Bawi and Miran (100% working interest, operator)
Negotiations between Genel and the KRG are ongoing regarding commercial terms for a staged and integrated oil and gas development.

In line with Genel's strategy, the development of Bina Bawi (and in the future, Miran) is set to be done in phases. Through disciplined allocation of capital, Genel is focused on aligning stakeholders and setting the framework for an attractive and investable project.

Genel and the KRG are now aligned on a phase one upstream project scope delivering a reduced c.250 MMscfd raw gas. The KRG and Genel will jointly fund the midstream gas development required to process the raw gas, partly making use of revenues from the accelerated development of Bina Bawi oil.

Discussions are ongoing, with regular meetings taking place between the KRG and Genel. Genel has recently made a formal proposal consistent with previously negotiated terms, balancing initial returns from the development of oil with the medium-term requirement for funding the midstream development.

Genel is seeking approval for this proposal and the Bina Bawi field development plan in order to commence with the oil development and commission a FEED study for the award of an Engineering, Procurement, Construction, Installation & Commissioning ('EPCIC') contract relating to the midstream development. The latter would take around 12 months, and be funded via the Bina Bawi oil development.

African exploration

Onshore Somaliland, interpretation of the 2018 2D seismic data together with continued basin analysis has led to the maturation of a prospects and leads inventory for the SL10B13 block (Genel 75% working interest and operator) which confirms the longstanding view that the block has significant hydrocarbon potential. A number of potentially high impact exploration targets have been identified within play types directly analogous to the prolific Yemeni rift basins.

Once these prospects and leads have been quantified in terms of volumetric potential and associated geological risk the Company will initiate a farm-out campaign, commencing late Q3 2019. This remains consistent with the Company's capital allocation approach, as long-term reserves replacement from legacy African exploration assets is targeted through the lowest possible capital outlay. On the Odewayne block further seismic processing is continuing in order to complete the Company's understanding of the prospectivity of the block. In both cases the minimum work commitments and associated expenditure for the current licence periods has been met.

On the Sidi Moussa block offshore Morocco (Genel 75% working interest, operator), processing of the multi-azimuth broadband 3D seismic survey acquired in 2018 over the prospective portions of the block continues. This completes the work obligations associated with the current licence period. Once completed, the Company plans to initiate a farm-out campaign in Q1 2020, aimed at bringing a partner onto the licence prior to considering further commitments. The Company is currently engaged in discussions with the Moroccan Government with respect to the requisite licence time to complete this forward plan.

FINANCIAL REVIEW

For 2019 the financial priorities of the Company are the following:

- Continued focus on capital allocation, with prioritisation of highest value investment in assets with ongoing or near-term cash and value generation
- Investment in lower risk development of opportunities with high potential. This currently includes the delivery of first oil at Sarta and drilling a well on a discovered resource at Qara Dagh. Investment at Bina Bawi will be added should appropriate commercial terms and conditions be reached
- Continued focus on acquiring assets with the potential to add significant value to the Company through near to mid-term cash generation. The objective is to establish a portfolio of assets that strengthens the portfolio of Sarta, Qara Dagh and Bina Bawi oil in replacing and increasing the Company's cash generation when the override royalty agreement ends in Q3 2022, and also to augment gas development to grow cash generation thereafter. Overall putting together a funnel that supports continuing material free cash flow well into the next decade and providing the basis for a progressive dividend
- Continued focus on the capital structure of the Company
  - Genel is committed to distributing a minimum of $40 million in dividends each year. Given the forecast free cash flow of the Company, this figure is expected to grow

In the first half of the year, successful delivery of these priorities has produced positive results. Pro forma free cash flow of $75.6 million, which includes post period receipt of $18.9 million, represents an increase of 8% on the prior year, despite the $5/bbl fall in Brent oil price and increased investment of $30 million in production and pre-production assets:

(all figures $ million)	**H1 2019**	H1 2018	FY 2018
Operating cash flow and other	**142.3**	125.1	299.2
Producing asset cost recovered capex	**(48.7)**	(29.5)	(65.3)
Development capex	**(9.4)**	-	-
Exploration and appraisal capex	**(12.2)**	(10.5)	(39.7)
Interest and other	**(15.3)**	(15.0)	(30.0)
Free cash flow	**56.7**	70.1	164.2
Cash received post period end	**18.9**	-	-
Pro forma free cash flow	**75.6**	70.1	164.2

This increase in capital expenditure principally relates to increased investment at Peshkabir and Sarta.

Peshkabir is our priority for capital allocation. Due to well productivity and positive commercial terms, capital investment is recovered within three months. Investment in this asset has resulted in the material increase in production, currently c.55,000 bopd, increased central processing capacity to 55,000 bopd and optimisation of costs by building pipeline transportation to replace trucking, which reduces transportation costs by 50¢ per barrel.

Sarta represents significant growth potential, with current work focused on building towards first oil in the middle of 2020.

Other spend in the year has been focused on preparation for drilling at Qara Dagh, and drilling production wells and water disposal wells at Tawke, Peshkabir and Taq Taq. We now plan to drill two additional wells at both Peshkabir and Taq Taq, with capital expenditure expected to be towards the top end of the previously provided range of $150-170 million.

In January we indicated our expectation of free cash generation of $100 million at $45/bbl. Since then we have added the Sarta and Qara Dagh assets. With the additional capex on these assets estimated to be around $50 million, we now expect material free cash generation for the full year, which excludes dividend payments, to be in excess of $100 million.

We will continue to be disciplined in our capital allocation and invest in areas where we can deliver value. This applies both to allocation of capital to the existing portfolio and also to assets or opportunities that we acquire.

Rigorous cost management is maintained across all operations, while ensuring spend is sufficient to take advantage of the growth opportunities in the portfolio.

A summary of the financial results for the year is provided below.

Financial results for the half-year

Income statement
Working interest production of 37,400 bopd was higher than the first half last year (H1 2018: 32,100 bopd), which principally benefited from more than doubled Peshkabir production.

Revenue has increased by 21% compared to H1 2018, from $161.1 million to $194.3 million, with the decrease in the average Brent oil price of $66/bbl (H1 2018: $71/bbl) being offset by the improvement in production. Production costs of $18.1 million (H1 2018: $12.1 million) were higher due to increased production, with opex per barrel at c.$2.7/bbl compared to c.$2.1/bbl in the first half this year. The increase has been caused by trucking costs at Peshkabir - we expect trucking to be replaced by the pipeline in the second half of the year.

General and administration costs were $9.5 million (H1 2018: $11.8 million), of which cash costs were $7.2 million (H1 2018: $8.6 million). The reduction from the prior period is a result of higher capitalisation as capital activity has increased, principally at Sarta and Qara Dagh.

The increase in revenue resulted in a net increase in EBITDAX of $29.9 million compared to last period.

(all figures $ million)	**H1 2019**	H1 2018	FY 2018
Revenue	**194.3**	161.1	355.1
Operating costs	**(18.1)**	(12.1)	(28.7)
G&A (excl. depreciation)	**(8.9)**	(11.6)	(22.3)
EBITDAX	**167.3**	137.4	304.1
Depreciation and amortisation	**(74.8)**	(63.6)	(136.2)
Exploration (expense) / credit	**(0.6)**	(0.5)	1.5
Impairment of intangible assets	**-**	-	(424.0)
Operating profit / (loss)	**91.9**	73.3	(254.6)

EBITDAX is presented in order for the users of the financial statements to understand the cash profitability of the Company, which excludes the impact of costs attributable to exploration activity, which tend to be one-off in nature, and the non-cash costs relating to depreciation, amortisation and impairments. EBITDAX is used as the basis for underlying earnings per share, for the reasons provided above.

Bond interest expense of $15.0 million was in line with prior year. Finance income of $2.4 million (H1 2018: $2.1 million) was bank interest, finance expense of $2.9 million (H1 2018: $1.1 million) included a non-cash discount unwind expense on liabilities, and fees related to the bondholder waiver. There is no taxation on operational profits: under the terms of the Kurdistan Region of Iraq ('KRI') PSC's, corporate income tax due is paid on behalf of the Company by the KRG from the KRG's own share of revenues, resulting in no corporate income tax payment required or expected to be made by the Company. Tax presented in the income statement of $0.4 million (H1 2018: nil) was related to taxation of the service companies. Depreciation and amortisation of oil assets has increased overall by $10.8 million as a result of higher production.

Capital expenditure
Capital expenditure is the aggregation of additions to property, plant and equipment ($64.6 million) and intangible assets ($7.6 million) and is reported to provide investors with an understanding of the quantum and nature of investment that is being made in the business. Capital expenditure for the period was $72.2 million, predominantly focused on production assets and the Sarta PSC ($11.3m):

(all figures $ million)	**H1 2019**	H1 2018	FY 2018
Cost recovered production capex	**53.3**	27.8	70.4
Pre-production capex - oil	**11.3**	-	-
Pre-production capex - gas	**5.6**	5.7	12.0
Other exploration and appraisal capex	**2.0**	0.6	13.1
Capital expenditure	**72.2**	34.1	95.5

Cash flow, cash, net cash and debt
Free cash flow is presented in order to show the free cash generated that is available for the Board to invest in the business. The measure provides the reader a better understanding of the underlying business cash flows. Free cash flow was $56.7m, with an overall increase in cash of $19.0m in the period compared to an increase of $71.2 million last period:

(all figures $ million)	**H1 2019**	H1 2018	FY 2018
Free cash flow	**56.7**	70.1	164.2
Dividend paid	**(29.0)**	-	-
Purchase of shares	**(8.7)**	-	-
Release of restricted cash and other	**-**	1.1	8.1
Net change in cash	**19.0**	71.2	172.3
Opening cash	334.3	162.0	162.0
Closing cash	**353.3**	233.2	334.3
Debt reported under IFRS	(297.5)	(297.0)	(297.3)
Net cash / (debt)	**55.8**	(63.8)	(37.0)

Closing cash of $353.3 million excludes restricted cash of $10.0 million (H1 2018: $17.5 million), which is also excluded from net cash at 30 June 2019 of $55.8 million. Net cash is reported in order for users of the financial statements to understand how much cash remains if the Company paid its debt obligations from its available cash on the period end date.

Reported IFRS debt was $297.5 million (31 December 2018: $297.3 million), comprised of $300 million of bond debt less amortised costs. The bond pays a 10.0% coupon and matures in December 2022. The bond has three financial covenant maintenance tests:

Financial covenant	Test	**H1 2019**
Net debt / EBITDAX (rolling 12 months)	< 3.0	**(0.2)**
Equity ratio (Total equity/Total assets)	> 40%	**71%**
Minimum liquidity	> $30m	**$353m**

A reconciliation of debt and cash is provided in note 11 to the financial statements.

Net assets
Net assets at 30 June 2019 were $1,373.6 million (31 December 2018: $1,331.4 million) and consist primarily of oil and gas assets of $1,437.3 million (31 December 2018: $1,384.2 million), trade receivables of $116.6 million (31 December 2018: $94.8 million) and net cash of $55.8 million (31 December 2018: $37.0 million).

Liquidity / cash counterparty risk management
The Company monitors its cash position, cash forecasts and liquidity on a regular basis. The Company holds surplus cash in treasury bills or on time deposits with a number of major financial institutions. Suitability of banks is assessed using a combination of sovereign risk, credit default swap pricing and credit rating.

Dividend
Maiden dividend distribution of $27.4 million (2018: nil) paid to shareholders in June 2019. A n interim dividend of 5¢ per share has been confirmed:

- Ex-dividend date: 12 December2019
- Record Date: 13 December 2019
- Payment Date: 8 January 2020

Going concern
The Directors have assessed that the Company's forecast liquidity provides adequate headroom over forecast expenditure for the 12 months following the signing of the half-year condensed consolidated financial statements for the period ended 30 June 2019 and consequently that the Company is considered a going concern.

Principal risks and uncertainties
The Company is exposed to a number of risks and uncertainties that may seriously affect its performance, future prospects or reputation and may threaten its business model, future performance, solvency or liquidity. The following risks are the principal risks and uncertainties of the Company, which are not all of the risks and uncertainties faced by the Company: the development and recovery of oil reserves; reserve replacement; commercialisation of the KRI gas business; M&A activity; the KRI natural resources industry and regional risk; corporate governance failure; capital structure and financing; local community support; the environmental impact of oil and gas extraction; and health and safety risks. Further detail on many of these risks was provided in the 2018 Annual Report. Since year-end, the environmental impact of oil and gas extraction has been added to the risk register, reflecting the increased focus on ESG issues.

Statement of directors' responsibilities
The directors confirm that these condensed interim financial statements have been prepared in accordance with International Accounting Standard 34, 'Interim Financial Reporting', as adopted by the European Union and that the interim management report includes a true and fair review of the information required by DTR 4.2.7 and DTR 4.2.8, namely:

- an indication of important events that have occurred during the first six months and their impact on the condensed set of financial statements, and a description of the principal risks and uncertainties for the remaining six months of the financial year; and
- material related-party transactions in the first six months and any material changes in the related-party transactions described in the last annual report.

The directors of Genel Energy plc are listed in the Genel Energy plc Annual Report for 31 December 2018. A list of current directors is maintained on the Genel Energy plc website: www.genelenergy.com

By order of the Board

Bill Higgs
CEO
5 August 2019

Esa Ikaheimonen
CFO
5 August 2019

Condensed consolidated statement of comprehensive income
For the period ended 30 June 2019

	Notes	**6 months to 30 June 2019 $m**	6 months to 30 June 2018 $m	Year to 31 Dec 2018 $m
Revenue	3	**194.3**	161.1	355.1
Production costs	4	**(18.1)**	(12.1)	(28.7)
Depreciation and amortisation of oil assets	4	**(74.2)**	(63.4)	(134.5)
Gross profit		**102.0**	85.6	191.9
Exploration (expense) / credit	4	**(0.6)**	(0.5)	1.5
Impairment of intangible assets	4	**-**	-	(424.0)
General and administrative costs	4	**(9.5)**	(11.8)	(24.0)
Operating profit / (loss)		**91.9**	73.3	(254.6)
Operating profit / (loss) is comprised of:				
EBITDAX		***167.3***	*137.4*	*304.1*
Depreciation and amortisation		***(74.8)***	*(63.6)*	*(136.2)*
Exploration (expense) / credit	*4*	***(0.6)***	*(0.5)*	*1.5*
Impairment of intangible assets	*4*	***-***	*-*	*(424.0)*
Finance income	5	**2.4**	2.1	4.4
Bond interest expense	5	**(15.0)**	(15.0)	(30.0)
Other finance expense	5	**(2.9)**	(1.1)	(3.2)
Profit / (loss) before income tax		**76.4**	59.3	(283.4)
Income tax expense	6	**(0.4)**	-	(0.2)
Profit / (loss) and total comprehensive income / (expense)		**76.0**	59.3	(283.6)
Attributable to:				
Shareholders' equity		**76.0**	59.3	(283.6)
		76.0	59.3	(283.6)
Profit / (loss) per ordinary share		**¢**	¢	¢
Basic	7	**27.2**	21.3	(101.6)
Diluted	7	**27.1**	21.2	(101.6)

Condensed consolidated balance sheet
At 30 June 2019

	Notes	**30 June 2019 $m**	30 June 2018 $m	31 Dec 2018 $m
Assets				
Non-current assets				
Intangible assets	8	**796.1**	1,264.1	818.4
Property, plant and equipment	9	**641.2**	559.5	565.8
		1,437.3	1,823.6	1,384.2
Current assets				
Trade and other receivables	10	**125.6**	88.3	99.4
Restricted cash	11	**10.0**	17.5	10.0
Cash and cash equivalents	11	**353.3**	233.2	334.3
		488.9	339.0	443.7
Total Assets		**1,926.2**	2,162.6	1,827.9
Liabilities				
Non-current liabilities				
Trade and other payables		**(120.8)**	(74.5)	(76.8)
Deferred income		**(28.1)**	(33.8)	(31.9)
Provisions		**(34.7)**	(31.0)	(32.9)
Borrowings	11	**(297.5)**	(297.0)	(297.3)
		(481.1)	(436.3)	(438.9)
Current liabilities				
Trade and other payables		**(65.3)**	(48.1)	(52.6)
Deferred income		**(6.2)**	(5.3)	(5.0)
		(71.5)	(53.4)	(57.6)
Total liabilities		**(552.6)**	(489.7)	(496.5)
Net assets		**1,373.6**	1,672.9	1,331.4
Owners of the parent				
Share capital		**43.8**	43.8	43.8
Share premium account		**4,046.6**	4,074.2	4,074.2
Accumulated losses		**(2,716.8)**	(2,445.1)	(2,786.6)
Total equity		**1,373.6**	1,672.9	1,331.4

Condensed consolidated statement of changes in equity
For the period ended 30 June 2019

	Share capital $m	Share premium $m	Accumulated losses $m		Total equity $m
At 1 January 2018	43.8	4,074.2	(2,508.2)		1,609.8
Profit and total comprehensive income	-	-	59.3		59.3
Share-based payments	-	-	3.8		3.8
At 30 June 2018	43.8	4,074.2	(2,445.1)		1,672.9
At 1 January 2018	43.8	4,074.2	(2,508.2)		1,609.8
(Loss) and total comprehensive (expense)	-	-	(283.6)		(283.6)
Share-based payments	-	-	5.2		
				5.4	5.2
At 31 December 2018 and 1 January 2019	43.8	4,074.2	(2,786.6)		1,331.4
Profit and total comprehensive income	**-**	**-**	**76.0**		**76.0**
Share-based payments	**-**	**-**	**2.5**		**2.5**
Purchase of shares to satisfy share awards	**-**	**-**	**(8.2)**		**(8.2)**
Purchase of treasury shares	**-**	**-**	**(0.5)**		**(0.5)**
Dividend payment	**-**	**(27.6)**[1]	**-**		**(27.6)**
At 30 June 2019	**43.8**	**4,046.6**	**(2,716.8)**		**1,373.6**

[1] The Companies (Jersey) Law 1991 does not define the expression "dividend" but refers instead to "distributions". Distributions may be debited to any account or reserve of the Company (including share premium account).

Condensed consolidated cash flow statement
For the period ended 30 June 2019

	Notes	**30 June 2019 $m**	30 June 2018 $m	31 Dec 2018 $m
Cash flows from operating activities				
Profit / (Loss) and total comprehensive income / (expense)		**76.0**	59.3	(283.6)
Adjustments for:				
Finance income	5	**(2.4)**	(2.1)	(4.4)
Bond interest expense	5	**15.0**	15.0	30.0
Other finance expense	5	**2.9**	1.1	3.2
Taxation		**0.4**	-	0.2
Depreciation and amortisation	4	**74.8**	63.6	136.2
Exploration expense / (credit)	4	**0.6**	0.5	(1.5)
Impairment of intangible assets	4	**-**	-	424.0
Other non-cash items		**(1.4)**	3.0	4.9
Changes in working capital:				
(Increase) / decrease in trade receivables		**(21.8)**	(11.1)	(21.5)
(Increase) / decrease in other receivables		**-**	0.9	(1.1)
Increase / (decrease) in trade and other payables		**(3.7)**	(7.1)	9.2
Cash generated from operations		**140.4**	123.1	295.6
Interest received	5	**2.4**	2.1	4.4
Taxation paid		**(0.5)**	(0.1)	(0.8)
Net cash generated from operating activities		**142.3**	125.1	299.2
Cash flows from investing activities				
Purchase of intangible assets		**(12.2)**	(10.5)	(39.7)
Purchase of property, plant and equipment		**(58.1)**	(29.5)	(65.3)
Restricted cash	11	**-**	1.0	8.5
Net cash used in investing activities		**(70.3)**	(39.0)	(96.5)
Cash flows from financing activities				
Dividends paid to company's shareholders	11	**(27.4)**	-	-
Dividend related expenses		**(1.6)**	-	-
Purchase of shares for employee share trust		**(8.2)**	-	-
Purchase of treasury shares	11	**(0.5)**	-	-
Lease payments	13	**(0.3)**	-	-
Interest paid		**(15.0)**	(15.0)	(30.0)
Net cash used in financing activities		**(53.0)**	(15.0)	(30.0)
Net increase / (decrease) in cash and cash equivalents		**19.0**	71.1	172.7
Foreign exchange income / (loss) on cash and cash				

equivalents		-	0.1	(0.4)
Cash and cash equivalents at 1 January		**334.3**	162.0	162.0
Cash and cash equivalents at period end	11	**353.3**	233.2	334.3

Notes to the condensed consolidated financial statements

1. Basis of preparation

Genel Energy Plc - registration number: 107897 (the Company) is a public limited company incorporated and domiciled in Jersey with a listing on the London Stock Exchange. The address of its registered office is 12 Castle Street, St Helier, Jersey, JE2 3RT.

The half-year condensed consolidated financial statements for the six months ended 30 June 2019 and six months ended 30 June 2018 are unaudited and have been prepared in accordance with the Disclosure and Transparency Rules of the Financial Conduct Authority and with IAS 34 'Interim Financial Reporting' as adopted by the European Union and were approved for issue on 6 August 2019. They do not comprise statutory accounts within the meaning of Article 105 of the Companies (Jersey) Law 1991. The half-year condensed consolidated financial statements should be read in conjunction with the annual financial statements for the year ended 31 December 2018, which have been prepared in accordance with IFRS as adopted by the European Union. The annual financial statements for the period ended 31 December 2018 were approved by the board of directors on 19 March 2019. The report of the auditors was unqualified, did not contain an emphasis of matter paragraph and did not contain any statement under the Companies (Jersey) Law 1991. The financial information for the year to 31 December 2018 has been extracted from the audited accounts.

There have been no changes in related parties since year-end and no related party transactions that had a material effect on financial position or performance in the period. There are not significant seasonal or cyclical variations in the Company's total revenues.

Going concern
The Company regularly evaluates its financial position, cash flow forecasts and its covenants by sensitizing with a range of scenarios which incorporates change in oil prices, discount rates, production volumes as well as capital and operational spend. As a result, the Directors have assessed that the Company's forecast liquidity provides adequate headroom over its forecast expenditure for the 12 months following the half-year condensed consolidated financial statements for the period ended 30 June 2019 and consequently that the Company is considered a going concern.

2. Accounting policies

The accounting policies adopted in preparation of these half-year condensed consolidated financial statements are consistent with those used in preparation of the annual financial statements for the year ended 31 December 2018.

The preparation of these half-year condensed consolidated financial statements in accordance with IFRS requires the Company to make judgements and assumptions that affect the reported results, assets and liabilities. Where judgements and estimates are made, there is a risk that the actual outcome could differ from the judgement or estimate made. The Company has assessed the following as being areas where changes in judgements or estimates could have a significant impact on the financial statements.

Significant estimates
The following are the critical estimates that the directors have made in the process of applying the Company's accounting policies and that has the most significant effect on the amounts recognised in the financial statements.

Estimation of hydrocarbon reserves and resources and associated production profiles and costs
Estimates of hydrocarbon reserves and resources are inherently imprecise and are subject to future revision. The Company's estimation of the quantum of oil and gas reserves and resources and the timing of its production, cost and monetisation impact the Company's financial statements in a number of ways, including: testing recoverable values for impairment; the calculation of depreciation, amortisation and assessing the cost and likely timing of decommissioning activity and associated costs.

Proven and probable reserves are estimates of the amount of hydrocarbons that can be economically extracted from the Company's assets. The Company estimates its reserves using standard recognised evaluation techniques. Assets assessed as proven and probable reserves ("2P" - generally accepted to have circa 50% probability) are generally classified as property, plant and equipment as development or producing assets and depreciated using the units of production methodology. The Company considers its best estimate for future production and quantity of oil within an asset based on a combination of internal and external evaluations and uses this as the basis of calculating depreciation and amortisation of oil and gas assets and testing for impairment.

Hydrocarbons that are not assessed as 2P are considered to be resources and are classified as exploration and evaluation assets. These assets are expenditures incurred before technical feasibility and commercial viability is demonstrable. Estimates of resources for undeveloped or partially developed fields are subject to greater uncertainty over their future life than estimates of reserves for fields that are substantially developed and being depleted and are likely to contain estimates and judgements with a wide range of possibilities. These assets are considered for impairment under IFRS 6.

Once a field commences production, the amount of proved reserves will be subject to future revision once additional information becomes available through, for example, the drilling of additional wells or the observation of long-term reservoir performance under producing conditions.

Assessment of reserves and resources are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves.

Estimation of oil and gas asset values
Estimation of the asset value of oil and gas assets is calculated from a number of inputs that require varying degrees of estimation. Principally oil and gas assets are valued by estimating the future cash flows based on a combination of reserves and resources, costs of appraisal, development and production, production profile and future sales price and discounting those cash flows at an appropriate discount rate.

Future costs of appraisal, development and production are estimated taking into account the level of development required to produce those reserves and are based on past costs, experience and data from similar assets in the region, future petroleum prices and the planned development of the asset. However, actual costs may be different from those estimated.

Discount rate is assessed by the Company using various inputs from market data, external advisers and internal calculations. A nominal discount rate of 12.5% is used when assessing the impairment testing of the Company's oil assets.

In addition, estimation of the recoverable amounts of both Miran and Bina Bawi CGUs, which are classified under IFRS as exploration and evaluation intangible assets and consequently carry the inherent uncertainty explained above, include the key assessment that the projects will progress, which is outside of the control of management and is dependent on the progress of government to government discussions regarding supply of gas and sanctioning of development of both of the midstream for gas and the upstream for oil. Lack of progress could result in significant delays in value realisation and consequently a lower asset value.

Estimation of future oil price and netback price
The estimation of future oil price has a significant impact throughout the financial statements, primarily in relation to the estimation of the recoverable value of property, plant and equipment, intangible assets. It is also relevant to the assessment of going concern.

Netback price is used to value the Company's revenue, trade receivables and its forecast cash flows used for impairment testing. It is the aggregation of realised price less transportation and handling costs. The Company does not have direct visibility on the components of the netback price realised for its oil because sales are managed by the KRG, but invoices are currently raised for payments on account using a netback price agreed with the KRG.

The trade receivable is recognised when the control on oil is transferred to the customer at the metering point, as this is the time the consideration becomes unconditional. The trade receivable reflects the Company's entitlement based on the netback price and oil transferred.

Acquisitions of Sarta and Qara Dagh PSCs

On 28 February 2019 the Company completed the acquisition of a 30% interest in the Sarta PSC, with an economic date of 1 January 2019. Shortly after acquisition date, final investment decision ("FID") was taken on phase 1A development, resulting in the recognition of gross 2P reserves at the asset level of 34mmbbls, of which the Company's share was 10mmbbls. The interest has been accounted for as an asset acquisition under IAS 16, with the result being the recognition of a development asset, reflecting the acquired 2P reserves. Consideration for the asset is a combination of cost recoverable carry and a milestone success payment and has been assessed based on the 2P reserves that have been recognised.

On the same date, the Company also completed the acquisition of a 40% interest in the Qara Dagh PSC. Consideration on the asset is cost recoverable carry arrangement on one well.

Business combinations

The recognition of business combinations requires the excess of the purchase price of acquisitions over the net book value of assets acquired to be allocated to the assets and liabilities of the acquired entity. The Company makes judgements and estimates in relation to the fair value allocation of the purchase price.

The fair value exercise is performed at the date of acquisition. Owing to the nature of fair value assessments in the oil and gas industry, the purchase price allocation exercise and acquisition date fair value determinations require subjective judgements based on a wide range of complex variables at a point in time. The Company uses all available information to make the fair value determinations.

In determining fair value for acquisitions, the Company utilises valuation methodologies including discounted cash flow analysis. The assumptions made in performing these valuations include assumptions as to discount rates, foreign exchange rates, commodity prices, the timing of development, capital costs, and future operating costs. Any significant change in key assumptions may cause the acquisition accounting to be revised.

Joint arrangements

Arrangements under which the Company has contractually agreed to share control with another party, or parties, are joint ventures where the parties have rights to the net assets of the arrangement, or joint operations where the parties have rights to the assets and obligations for the liabilities relating to the arrangement. Investments in entities over which the Company has the right to exercise significant influence but has neither control nor joint control are classified as associates and accounted for under the equity method.

The Company recognises its assets and liabilities relating to its interests in joint operations, including its share of assets held jointly and liabilities incurred jointly with other partners.

Farm-in/farm-out

Farm-out transactions relate to the relinquishment of an interest in oil and gas assets in return for services rendered by a third party or where a third party agrees to pay a portion of the Company's share of the development costs (cost carry). Farm-in transactions relate to the acquisition by the Company of an interest in oil and gas assets in return for services rendered or cost-carry provided by the Company.

Farm-in/farm-out transactions undertaken in the development or production phase of an oil and gas asset are accounted for as an acquisition or disposal of oil and gas assets. The consideration given is measured as the fair value of the services rendered or cost-carry provided and any gain or loss arising on the farm-in/farm-out is recognised in the statement of comprehensive income. A profit is recognised for any consideration received in the form of cash to the extent that the cash receipt exceeds the carrying value of the associated asset.

Farm-in/farm-out transactions undertaken in the exploration phase of an oil and gas asset are accounted for on a no gain/no loss basis due to inherent uncertainties in the exploration phase and associated difficulties in determining fair values reliably prior to the determination of commercially recoverable proved reserves. The resulting exploration and evaluation asset is then assessed for impairment indicators under IFRS 6.

New Standards

The following new accounting standards, amendments to existing standards and interpretations are effective on 1 January 2019. Amendments to IFRS 9 - *Prepayment Features with Negative Compensation*, Amendments to IAS 28 - *Long-term Interests in Associates and Joint Ventures*, Amendments to IAS 19 - *Plan Amendment, Curtailment or Settlement*, IFRIC 23 - *Uncertainty over Income Tax Treatments*, Annual Improvements to IFRS Standards 2015-2017 Cycle. The adoption of these standards and amendments has had no impact on the Company's results or financial statement disclosures.

The following new accounting standards, amendments to existing standards and interpretations have been issued but are not yet effective and have not yet been endorsed by the EU: Amendments to References to the Conceptual Framework in IFRS Standards (effective 1 Jan 2020), Amendment to IFRS 3 Business Combinations (effective 1 Jan 2020) and Amendments to IAS 1 and IAS 8: Definition of Material (effective 1 Jan 2020).

Changes in accounting policies

IFRS 16 - Leases, which became effective by 1 January 2019, requires the lessee to recognise the right to use the asset and the liability, depreciate the associated asset, re-measure and reduce the liability through lease payments; unless the underlying leased asset is of low value and/or short term in nature. The Company has adopted IFRS 16 retrospectively from 1 January 2019, but has not restated comparatives for the 2018 reporting period, as permitted under the specific transitional provisions in the standard. The reclassifications and the adjustments arising from the new leasing rules are therefore recognised in the opening balance sheet on 1 January 2019 and further explained in Note 13.

Financial risk factors

The Company's activities expose it to a variety of financial risks: credit risk, currency risk, interest risk and liquidity risk. Since th e half-year condensed consolidated financial statements do not include all financial risk management information and disclosures required in the annual financial statements; they should be read in conjunction with the Company's annual financial statements as at 31 December 2018. There have been no significant changes in any risk management policies since year end.

3. Segmental information

The Company has three reportable business segments: Oil, Miran/Bina Bawi ('MBB') and Exploration ('Expl.'). Capital allocation decisions for the oil segment are considered in the context of the cash flows expected from the production and sale of crude oil. The oil segment is comprised of the producing fields on the Tawke PSC and the Taq Taq PSC, development field on Sarta PSC and appraisal field on Qara Dagh PSC which are located in the KRI and make sales predominantly to the KRG. The Miran/Bina Bawi segment is comprised of the oil and gas upstream and midstream activity on the Miran PSC and the Bina Bawi PSC, which are both in the KRI - this was previously labelled as the 'Gas' segment. The exploration segment is comprised of exploration activity, principally located in Somaliland and Morocco. 'Other' includes corporate assets, liabilities and costs, elimination of intercompany receivables and intercompany payables, which are non-segment items.

6 months ended 30 June 2019

	Oil	MBB	Expl.	Other	Total

	$m	$m	$m	$m	$m
Revenue from contracts with customers	**188.7**	**-**	**-**	**-**	**188.7**
Revenue from other sources	**5.6**	**-**	**-**	**-**	**5.6**
Cost of sales	**(92.3)**	**-**	**-**	**-**	**(92.3)**
Gross profit	**102.0**	**-**	**-**	**-**	**102.0**
Exploration (expense) / credit	**-**	**(0.2)**	**(0.4)**	**-**	**(0.6)**
General and administrative costs	**-**	**-**	**-**	**(9.5)**	**(9.5)**
Operating profit / (loss)	**102.0**	**(0.2)**	**(0.4)**	**(9.5)**	**91.9**
Operating profit / (loss) is comprised of					
EBITDAX	***176.2***	**-**	**-**	***(8.9)***	***167.3***
Depreciation and amortisation	***(74.2)***	**-**	**-**	***(0.6)***	***(74.8)***
Exploration (expense) / credit	**-**	***(0.2)***	***(0.4)***	**-**	***(0.6)***
Finance income	**-**	**-**	**-**	**2.4**	**2.4**
Bond interest expense	**-**	**-**	**-**	**(15.0)**	**(15.0)**
Other finance expense	**(1.0)**	**(0.1)**	**-**	**(1.8)**	**(2.9)**
Profit / (loss) before tax	**101.0**	**(0.3)**	**(0.4)**	**(23.9)**	**76.4**
Capital expenditure	**64.6**	**5.6**	**2.0**	**-**	**72.2**
Total assets	**1,082.9**	**467.4**	**35.1**	**340.8**	**1,926.2**
Total liabilities	**(146.0)**	**(88.5)**	**(12.6)**	**(305.5)**	**(552.6)**

Revenue from contracts with customers includes $54.7 million (30 June 2018: $48.2 million, 31 December 2018: $105.4 million) arising from the 4.5% royalty interest on gross Tawke PSC revenue ending at the end of July 2022 ("the ORRI"). Total assets and liabilities in the other segment are predominantly cash and debt balances.

6 months ended 30 June 2018

	Oil $m	MBB $m	Expl. $m	Other $m	Total $m
Revenue from contracts with customers	158.9	-	-	-	158.9
Revenue from other sources	2.2	-	-	-	2.2
Cost of sales	(75.5)	-	-	-	(75.5)
Gross profit	85.6	-	-	-	85.6
Exploration expense	-	(0.2)	(0.3)	-	(0.5)
General and administrative costs	-	-	-	(11.8)	(11.8)
Operating profit / (loss)	85.6	(0.2)	(0.3)	(11.8)	73.3
Operating profit / (loss) is comprised of					
EBITDAX	*149.0*	-	-	*(11.6)*	*137.4*
Depreciation and amortisation	*(63.4)*	-	-	*(0.2)*	*(63.6)*
Exploration expense	-	*(0.2)*	*(0.3)*	-	*(0.5)*
Finance income	-	-	-	2.1	2.1
Bond interest expense	-	-	-	(15.0)	(15.0)
Other finance expense	(0.8)	(0.1)	-	(0.2)	(1.1)
Profit / (loss) before tax	84.8	(0.3)	(0.3)	(24.9)	59.3
Capital expenditure	27.8	5.7	0.6	-	34.1
Total assets	1,049.6	869.5	33.8	209.7	2,162.6
Total liabilities	(82.1)	(79.8)	(27.3)	(300.5)	(489.7)

Total assets and liabilities in the other segment are predominantly cash and debt balances.

For the period ended 31 December 2018

	Oil $m	MBB $m	Expl. $m	Other $m	Total $m
Revenue from contracts with customers	350.3	-	-	-	350.3
Revenue from other sources	4.8	-	-	-	4.8
Cost of sales	(163.2)	-	-	-	(163.2)
Gross profit	191.9	-	-	-	191.9

Exploration (expense) / credit	-	(0.4)	1.9	-	1.5
Impairment of intangible assets	-	(424.0)	-	-	(424.0)
General and administrative costs	-	-	-	(24.0)	(24.0)
Operating profit / (loss)	191.9	(424.4)	1.9	(24.0)	(254.6)
Operating profit / (loss) is comprised of					
EBITDAX	326.4	-	-	(22.3)	304.1
Depreciation and amortisation	*(134.5)*	-	-	*(1.7)*	*(136.2)*
Exploration (expense) / credit	-	*(0.4)*	*1.9*	-	*1.5*
Impairment of intangible assets	-	*(424.0)*	-	-	*(424.0)*
Finance income	-	-	-	4.4	4.4
Bond interest expense	-	-	-	(30.0)	(30.0)
Other finance expense	(1.7)	(0.2)	-	(1.3)	(3.2)
Profit / (Loss) before income tax	190.2	(424.6)	1.9	(50.9)	(283.4)
Capital expenditure	70.4	12.0	13.1	-	95.5
Total assets	1,015.4	457.7	35.5	319.3	1,827.9
Total liabilities	(89.1)	(84.4)	(16.1)	(306.9)	(496.5)

Total assets and liabilities in the other segment are predominantly cash and debt balances.

4. Operating costs

	6 months to 30 June 2019 **$m**	6 months to 30 June 2018 $m	Year to 31 December 2018 $m
Production costs	**18.1**	12.1	28.7
Depreciation of oil and gas property, plant and equipment	**39.7**	34.6	72.4
Amortisation of oil and gas intangible assets	**34.5**	28.8	62.1
Cost of sales	**92.3**	75.5	163.2
Exploration expense / (credit)	**0.6**	0.5	(1.5)
Impairment of intangible assets (note 8)	**-**	-	424.0
Corporate cash costs	**7.2**	8.6	17.4
Corporate share-based payment expense	**1.7**	3.0	4.9
Depreciation and amortisation of corporate assets	**0.6**	0.2	1.7
General and administrative expenses	**9.5**	11.8	24.0

5. Finance expense and income

	6 months to 30 June 2019 **$m**	6 months to 30 June 2018 $m	Year to 31 December 2018 $m
Bond interest payable	**(15.0)**	(15.0)	(30.0)
Other finance expense	**(2.9)**	(1.1)	(3.2)
Finance expense	**(17.9)**	(16.1)	(33.2)
Bank interest income	**2.4**	2.1	4.4
Finance income	**2.4**	2.1	4.4

Bond interest payable is the cash interest cost of Company bond debt. Other finance expense primarily relates to the discount unwind on the bond and the asset retirement obligation provision.

6. Income tax expense

Current tax expense is incurred on the profits of the Turkish and UK services companies. Under the terms of KRI PSC's, corporate income tax due is paid on behalf of the Company by the KRG from the KRG's own share of revenues, resulting in no corporate income tax payment required or expected to be made by the Company. It is not known at what rate tax is paid, but it is estimated that the current tax rate would be between 15% and 40%. If this was known it may result in a gross up of revenue with a corresponding debit entry to taxation expense with no net impact on the income statement or on cash. In addition, it would be necessary to assess whether any deferred tax asset or liability was required to be recognised.

7. Earnings per share

Basic
Basic earnings per share is calculated by dividing the profit attributable to equity holders of the Company by the weighted average number of shares in issue during the period.

	6 months to 30 June 2019 **$m**	6 months to 30 June 2018 $m	Year to 31 December 2018 $m
Profit / (Loss) attributable to equity holders of the Company ($m)	**76.0**	59.3	(283.6)
Weighted average number of ordinary shares - number [1]	**279,435,346**	279,025,723	279,065,717
Basic earnings / (loss) per share - cents per share	**27.2**	21.3	(101.6)

[1]Excluding shares held as treasury shares

Diluted
The Company purchases shares in the market to satisfy share plan requirements so diluted earnings per share is only adjusted for restricted shares not included in the calculation of basic earnings per share:

	6 months to 30 June 2019 $m	6 months to 30 June 2018 $m	Year to 31 December 2018 $m
Profit / (Loss) attributable to equity holders of the Company ($m)	**76.0**	59.3	(283.6)
Weighted average number of ordinary shares - number [1]	**279,435,346**	279,025,723	279,065,717
Adjustment for performance shares, restricted shares and share options	**812,852**	1,222,475	1,182,481
Total number of shares	**280,248,198**	280,248,198	280,248,198
Diluted earnings / (loss) per share - cents per share	**27.1**	21.2	(101.6)

[1]Excluding shares held as treasury shares

8. Intangible assets

	Exploration and evaluation assets $m	Tawke RSA $m	Other assets $m	Total $m
Cost				
At 1 January 2018	1,471.7	425.1	6.5	1,903.3
Additions	6.3	-	-	6.3
Discount unwind of contingent consideration	3.9	-	-	3.9
Other	(0.1)	-	-	(0.1)
At 30 June 2018	1,481.8	425.1	6.5	1,913.4
At 1 January 2018	1,471.7	425.1	6.5	1,903.3
Additions	25.1	-	0.3	25.4
Discount unwind of contingent consideration	8.1	-	-	8.1
Other	(11.7)	-	-	(11.7)
At 31 December 2018 and 1 January 2019	1,493.2	425.1	6.8	1,925.1
Additions	**7.6**	**-**	**0.4**	**8.0**
Discount unwind of contingent consideration	**4.3**	**-**	**-**	**4.3**
Other	**-**	**-**	**-**	**-**
At 30 June 2019	**1,505.1**	**425.1**	**7.2**	**1,937.4**
Accumulated amortisation and impairment				
At 1 January 2018	(581.3)	(32.8)	(6.3)	(620.4)
Amortisation charge for the period	-	(28.8)	(0.1)	(28.9)
At 30 June 2018	(581.3)	(61.6)	(6.4)	(649.3)
At 1 January 2018	(581.3)	(32.8)	(6.3)	(620.4)
Amortisation charge for the period	-	(62.1)	(0.2)	(62.3)
Impairment	(424.0)	-	-	(424.0)
At 31 December 2018 and 1 January 2019	(1,005.3)	(94.9)	(6.5)	(1,106.7)
Amortisation charge for the period	**-**	**(34.5)**	**(0.1)**	**(34.6)**
At 30 June 2019	**(1,005.3)**	**(129.4)**	**(6.6)**	**(1,141.3)**
Net book value				
At 30 June 2018	900.5	363.5	0.1	1,264.1
At 31 December 2018	487.9	330.2	0.3	818.4
At 30 June 2019	**499.8**	**295.7**	**0.6**	**796.1**

CGU carrying value		**30 Jun 2019 $m**	31 Dec 2018 $m
Bina Bawi PSC	*Discovered gas and oil, appraisal*	**347.4**	338.7
Miran PSC	*Discovered gas and oil, appraisal*	**117.9**	116.2
Somaliland PSC	*Exploration*	**33.4**	33.0
Qara Dagh PSC	*Exploration / Appraisal*	**1.1**	-
Exploration and evaluation assets		**499.8**	487.9
Tawke overriding royalty		**188.5**	217.5
Tawke capacity building payment waiver		**107.2**	112.7
Tawke RSA assets		**295.7**	330.2

The table below shows the indicative sensitivity of the Bina Bawi CGU net present value to changes to long term Brent, discount rate or production and reserves, assuming no change to other inputs.

	$m
Long term Brent +/- $5/bbl	+/- 13
Discount rate +/-2.5%	+/- 101
Production and reserves +/- 10%	+/- 32

9. Property, plant and equipment

Producing assets $m	Development assets $m	Other assets $m	Total $m

Cost				
At 1 January 2018	2,683.9	-	9.4	2,693.3
Additions	27.8	-	-	27.8
Non-cash additions for ARO/share-based payments	1.4	-	-	1.4
At 30 June 2018	2,713.1	-	9.4	2,722.5
At 1 January 2018	2,683.9	-	9.4	2,693.3
Additions	70.4	-	0.2	70.6
Non-cash additions for ARO/share-based payments	2.9	-	-	2.9
At 31 December 2018 and 1 January 2019	2,757.2	-	9.6	2,766.8
Asset acquisitions	**-**	**49.4**	**-**	**49.4**
Additions	**53.3**	**11.3**	**-**	**64.6**
Right-of-use assets (note 13)	**-**	**-**	**1.9**	**1.9**
Net change in payable	**-**	**(1.9)**	**-**	**(1.9)**
Non-cash additions for ARO/share-based payments	**1.6**	**-**	**-**	**1.6**
At 30 June 2019	**2,812.1**	**58.8**	**11.5**	**2,882.4**
Accumulated depreciation and impairment				
At 1 January 2018	(2,119.7)	-	(8.6)	(2,128.3)
Depreciation charge for the period	(34.6)	-	(0.1)	(34.7)
At 30 June 2018	(2,154.3)	-	(8.7)	(2,163.0)
At 1 January 2018	(2,119.7)	-	(8.6)	(2,128.3)
Depreciation charge for the period	(72.4)	-	(0.3)	(72.7)
At 31 December 2018 and 1 January 2019	(2,192.1)	-	(8.9)	(2,201.0)
Depreciation charge for the period	**(39.7)**	**-**	**(0.5)**	**(40.2)**
At 30 June 2019	**(2,231.8)**	**-**	**(9.4)**	**(2,241.2)**
Net book value				
At 30 June 2018	558.8	-	0.7	559.5
At 31 December 2018	565.1	-	0.7	565.8
At 30 June 2019	**580.3**	**58.8**	**2.1**	**641.2**

CGU carrying value		**30 Jun 2019 $m**	31 Dec 2018 $m
Tawke PSC	*Oil production*	**488.5**	478.2
Taq Taq PSC	*Oil production*	**91.8**	86.9
Producing assets		**580.3**	565.1
Sarta PSC	*Oil development*	**58.8**	-

Asset acquisitions of $49.4 million relates to the Sarta PSC. Further explanation on oil and gas assets is provided in the significant accounting judgements and estimates in note 2. The sensitivities below provide an indicative impact on net present value of a change in long term Brent, discount rate or production and reserves, assuming no change to any other inputs.

	Taq Taq CGU $m	**Tawke CGU $m**
Long term Brent +/- $5/bbl	+/- 3	+/- 28
Discount rate +/-2.5%	+/- 5	+/- 52
Production and reserves +/-10%	+/- 9	+/- 71

10. Trade and other receivables

	30 June 2019 $m	30 June 2018 $m	31 Dec 2018 $m
Trade receivables	**116.6**	84.4	94.8
Other receivables and prepayments	**9.0**	3.9	4.6
	125.6	88.3	99.4

Trade receivables are amounts owed for the revenue from contracts with customers. The Company reports trade receivables net of any capacity building payables (30 June 2019: $4.2 million 31 December 2018: $1.9 million).

Under the Tawke and Taq Taq PSCs, payment for entitlement is due within 30 days. Since February 2016, a track record of payments being received three months after invoicing has been established, and consequently three months has been assessed as the established operating cycle under IAS 1. At 30 June 2019, $18.9M relating to the entitlement arising from the Tawke PSC had not been received. This was caused by operator banking issues, with the balance received on 9 July. The fair value of trade receivables is broadly in line with the carrying value.

Movement on trade receivables in the period

	30 June 2019 $m	30 June 2018 $m	31 Dec 2018 $m
Carrying value at 1 January	**94.8**	73.3	73.3
Revenue from contracts with customers	**188.7**	158.9	350.3
Cash proceeds	**(167.5)**	(150.9)	(335.1)
Capacity building payments	**0.6**	3.1	6.3
Carrying value at period end	**116.6**	84.4	94.8

11. Borrowings and net cash / (net debt)

30 June 2019	1 Jan 2019 $m	Discount unwind $m	Dividend paid $m	Net change in cash $m	30 June 2019 $m
2022 Bond 10.0%	(297.3)	(0.2)	-	-	(297.5)
Cash	334.3	-	(27.4)	46.4	353.3
Net Cash	**37.0**	**(0.2)**	**(27.4)**	**46.4**	**55.8**

The fair value of the bonds is $315.8 million (31 December 2018: $308.3 million, 30 June 2018: $307.5 million).

30 June 2018	1 Jan 2018 $m	Discount unwind $m	Other $m	Net change in cash $m	30 June 2018 $m
2022 Bond 10.0%	(296.8)	(0.1)	(0.1)	-	(297.0)
Cash	162.0	-	-	71.2	233.2
(Net Debt)	(134.8)	(0.1)	(0.1)	71.2	(63.8)

31 December 2018	1 Jan 2018 $m	Discount unwind $m	Net change in cash $m	31 Dec 2018 $m
2022 Bond 10.0%	(296.8)	(0.5)	-	(297.3)
Cash	162.0	-	172.3	334.3
Net Cash	(134.8)	(0.5)	172.3	37.0

12. Capital commitments

Under the terms of its PSCs and JOAs, the Company has certain commitments that are generally defined by activity rather than spend. The Company's capital programme for the next few years is explained in the operating review and is in excess of the activity required by its PSCs and JOAs.

13. Right-of-use assets / Lease liabilities

The Company's right-of-use assets are related to office, car and warehouse rents. The Company has elected to apply the transition exemptions for short-term and low-value leases. These leases are expensed when they incur.

Drill rig contracts are service contracts where contractors provide the rig together with the services and the contracted personnel on a day-rate basis for the purpose of drilling exploration or development wells. The Company has no right of use of the rigs. The aggregate payments under drilling contracts are determined by the number of days required to drill each well and are capitalised as exploration or development assets as appropriate.

	Right-of-use assets $m
Cost	
At 1 January 2019	1.9
Additions	-
At 30 June 2019	**1.9**
Accumulated depreciation	
At 1 January 2019	-
Depreciation charge for the period	**(0.3)**
At 30 June 2019	**(0.3)**
Net book value	
At 1 January 2019	1.9
At 30 June 2019	**1.6**

On adoption of IFRS 16, the Company recognised lease liabilities which were measured at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease. If that rate cannot be determined, the Company's incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions. Right-of-use assets are depreciated over the lifetime of the related lease contract. The lease terms vary from one to five years.

	Lease liabilities $m
At 1 January 2019	(1.9)
Payments of lease liabilities	**0.3**
At 30 June 2019	**(1.6)**

Included within lease liabilities of $1.6 million are non-current lease liabilities of $1.0 million. The identified leases have no significant impact on the Company's financing, bond covenants or dividend policy. The Company does not have any residual value guarantees. Extension options are included in the lease liability when it, based on the management's judgement, is reasonably certain that an extension will be exercised. As at 30 June 2019, the contractual maturities of the Company's lease liabilities are as follows:

	Less than 1 year $m	Between 1 -2 years $m	Between 2 - 5 years $m	Total contractual cash flow $m	Carrying Amount $m
Lease liabilities	(0.7)	(0.7)	(0.3)	**(1.7)**	**(1.6)**

Independent review report to Genel Energy plc

Report on the unaudited results for the period ended 30 June 2019

Our conclusion

We have reviewed Genel Energy plc's unaudited results for the period ended 30 June 2019 (the "interim financial statements") in the half-year results of Genel Energy plc for the 6 month period ended 30 June 2019. Based on our review, nothing has come to our attention that causes us to believe that the interim financial statements are not prepared, in all material respects, in accordance with International Accounting Standard 34, 'Interim Financial Reporting', as adopted by the European Union and the Disclosure Guidance and Transparency Rules sourcebook of the United Kingdom's Financial Conduct Authority.

What we have reviewed
The interim financial statements comprise:

- the condensed consolidated balance sheet as at 30 June 2019;
- the condensed consolidated statement of comprehensive income for the period then ended;
- the condensed consolidated cash flow statement for the period then ended;
- the condensed consolidated statement of changes in equity for the period then ended; and
- the explanatory notes to the interim financial statements.

The interim financial statements included in the half-year results have been prepared in accordance with International Accounting Standard 34, 'Interim Financial Reporting', as adopted by the European Union and the Disclosure Guidance and Transparency Rules sourcebook of the United Kingdom's Financial Conduct Authority.

As disclosed in note 1 to the interim financial statements, the financial reporting framework that has been applied in the preparation of the full annual financial statements of the Group is applicable law and International Financial Reporting Standards (IFRSs) as adopted by the European Union.

Responsibilities for the interim financial statements and the review

Our responsibilities and those of the directors
The half-year results, including the interim financial statements, is the responsibility of, and has been approved by, the directors. The directors are responsible for preparing the half-year results in accordance with the Disclosure Guidance and Transparency Rules sourcebook of the United Kingdom's Financial Conduct Authority.

Our responsibility is to express a conclusion on the interim financial statements in the half-year results based on our review. This report, including the conclusion, has been prepared for and only for the company for the purpose of complying with the Disclosure Guidance and Transparency Rules sourcebook of the United Kingdom's Financial Conduct Authority and for no other purpose. We do not, in giving this conclusion, accept or assume responsibility for any other purpose or to any other person to whom this report is shown or into whose hands it may come save where expressly agreed by our prior consent in writing.

What a review of interim financial statements involves
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.

We have read the other information contained in the half-year results and considered whether it contains any apparent misstatements or material inconsistencies with the information in the interim financial statements.

PricewaterhouseCoopers LLP
Chartered Accountants
London
5 August 2019

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