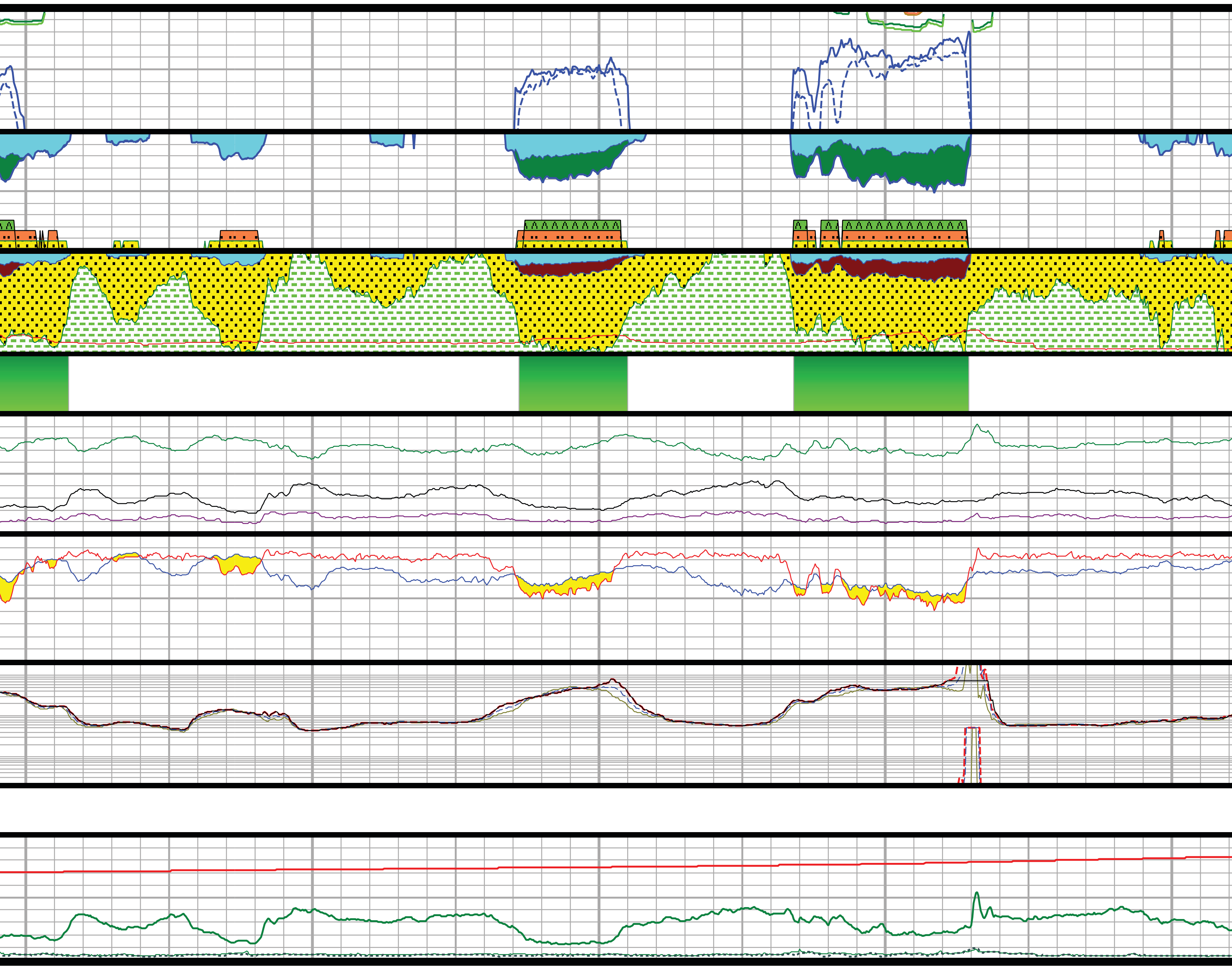
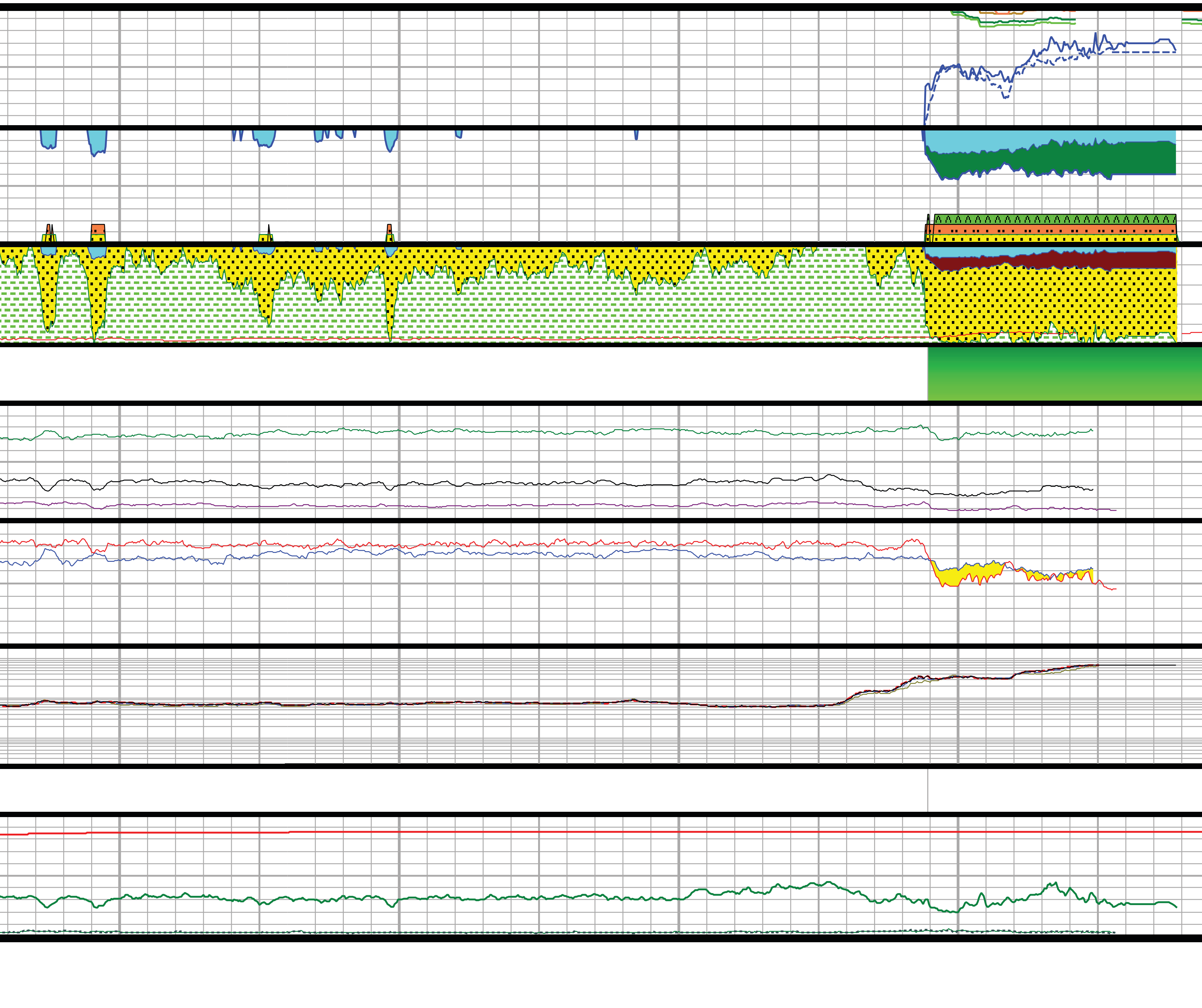
KRISENERGY

2018 ANNUAL REPORT



KRISENERGY LTD. IS AN ASIAN-FOCUSED UPSTREAM OIL AND GAS COMPANY WITH A PORTFOLIO OF PRODUCING ASSETS AND NEAR-TERM DEVELOPMENT PROJECTS. IT ALSO HOLDS A PORTFOLIO OF EXPLORATION PROSPECTS AND LEADS TO CAPTURE FUTURE GROWTH.

An interpreted well log with reservoirs highlighted from the 2018/2019 infill drilling campaign at the Wassana oil field in the G10/48 licence in the Gulf of Thailand



2018 Review KrisEnergy's Portfolio

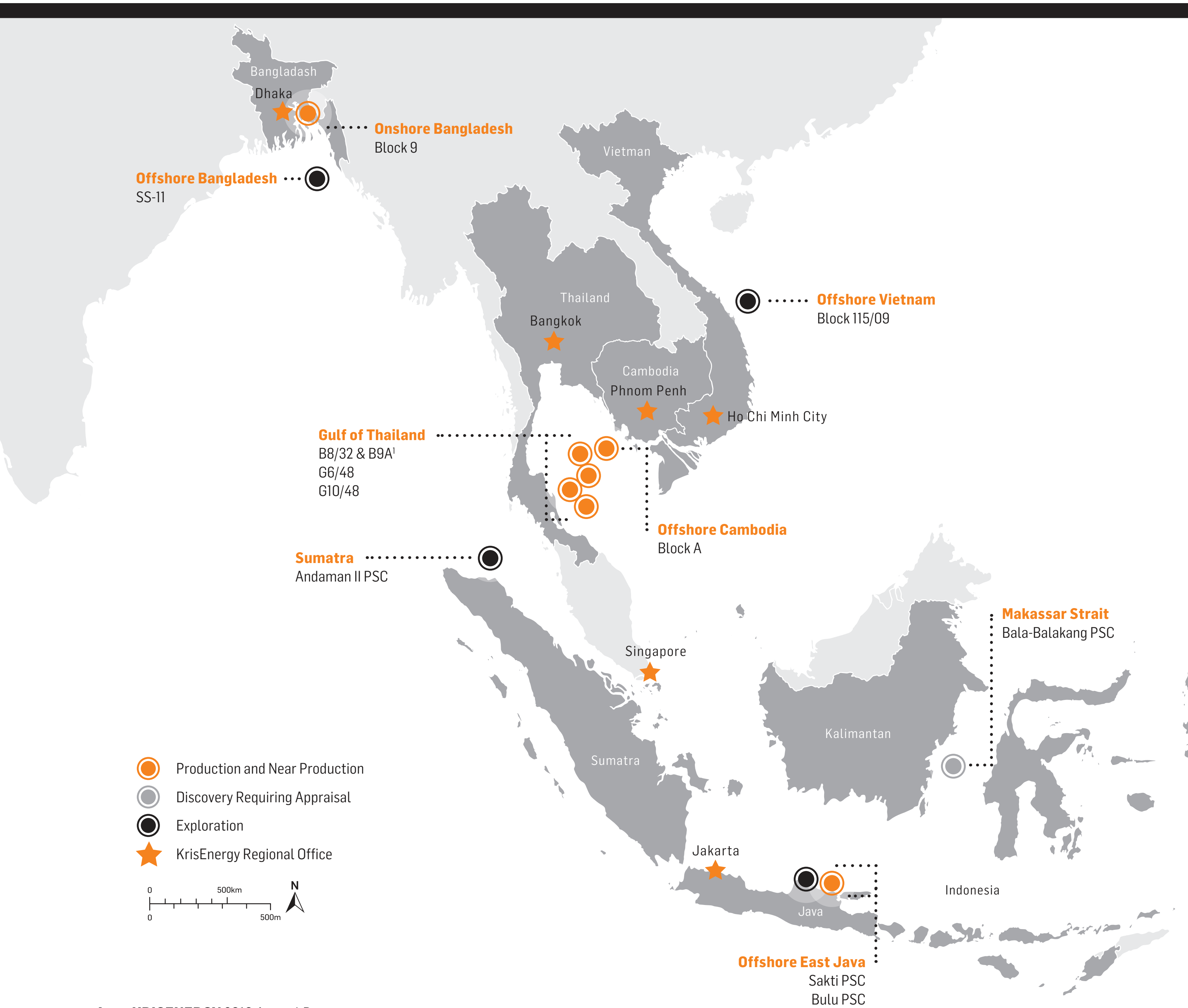
KRISENERGY'S PORTFOLIO SPANS FROM BANGLADESH IN THE WEST TO WEST PAPUA IN THE EAST AND FROM VIETNAM IN THE NORTH TO INDONESIA IN THE SOUTH.

Three of the contract areas produce crude oil, liquids and/or gas onshore Bangladesh and offshore in the Gulf of Thailand. In addition, the Group is the operator of oil development projects offshore Cambodia and offshore Thailand, and a gas development offshore Indonesia in the East Java Sea.

Our Offices

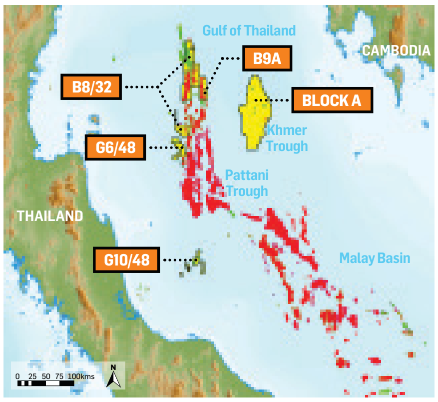
We are listed on the Mainboard of the Singapore Exchange Securities Trading Limited and have a corporate office in Singapore. We also maintain operational offices in Dhaka in Bangladesh, Phnom Penh in Cambodia, Jakarta in Indonesia, Bangkok in Thailand and Ho Chi Minh City in Vietnam. In addition, we have a full complement of operational staff at the Bangora gas field and facilities location, onshore Bangladesh, and at the Wassana oil field in the Gulf of Thailand.

We largely employ local technical and professional staff, who bring experience and knowledge of the regional geology, business culture and regulatory environment.

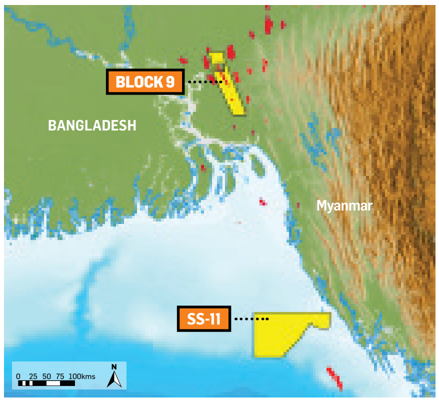


Country / Asset	Working Interest (%)	Operator	Gross Acreage (sq.km)	Location	Water Depths (m)
Bangladesh					
Block 9	30.0	KrisEnergy	1,770	Surma Basin	Onshore
SS-11	45.0	Ophir Energy	4,475	Bay of Bengal over Bengal Fan	200-1,500
Cambodia					
Block A	95.0	KrisEnergy	3,083	Khmer Basin, Gulf of Thailand	50-80
Gulf of Thailand					
B8/32 & B9A[1]	4.6345	Chevron	2,072	North Pattani Basin	42-113
G6/48		KrisEnergy		Karawake Basin on western margin of Pattani Basin	60-70
Production area	100.0[2]		88		
Reservation area	30.0		284		
G10/48	89.0	KrisEnergy	247	Southern margin of Pattani Basin	Up to 60
Indonesia					
Andaman II PSC	30.0	Premier Oil	7,400	North Sumatra Basin, Malacca Strait	200 to 1,950
Bala-Balakang PSC	85.0	KrisEnergy	838	Southern Kutai Basin, Makassar Strait	20 to over 1,000
Bulu PSC	42.5	KrisEnergy	697	East Java Sea	50-60
Sakti PSC	95.0	KrisEnergy	3,719	East Java Sea	50-60
Udan Emas PSC	100.0	KrisEnergy	1,070	Bintuni Basin, West Papua	Onshore
Vietnam					
Block 115/09	100.0	KrisEnergy	7,382	Quang Ngai Graben into Phu Khanh Basin	60-200

1 The Tantawan field in B8/32 and the Rajpruek field in B9A permanently ceased operation on 31 October 2017. Abandonment activities are underway before the B9A licence is relinquished
2 As of 18 February 2019, KrisEnergy has 100.0% working interest in the Exclusive Operation of the Rossukon field development plan

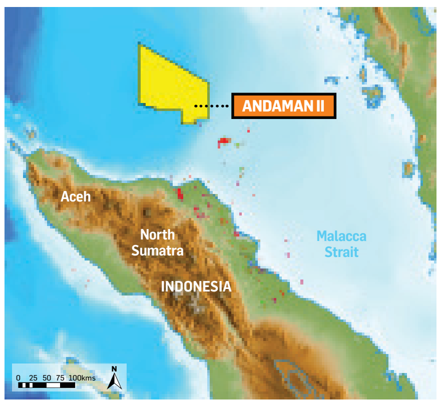


GULF OF THAILAND / OFFSHORE CAMBODIA

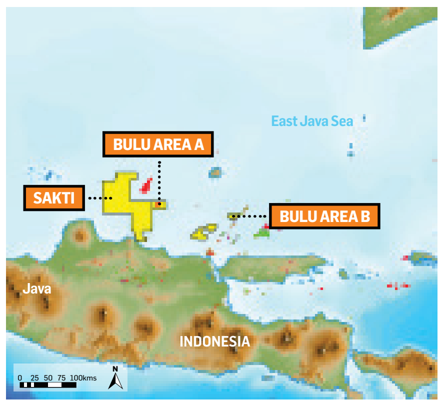


ONSHORE / OFFSHORE BANGLADESH

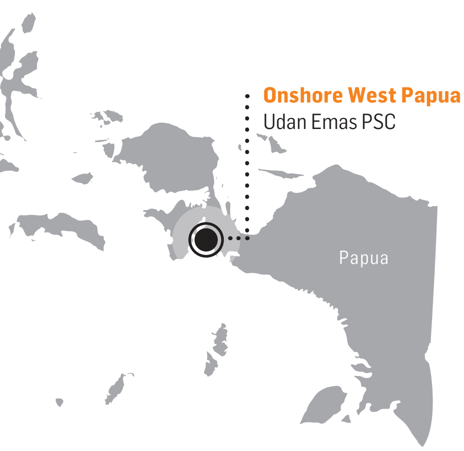
OFFSHORE VIETNAM



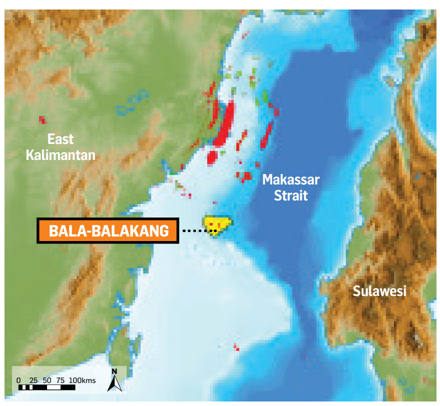
OFFSHORE NORTH SUMATRA, INDONESIA



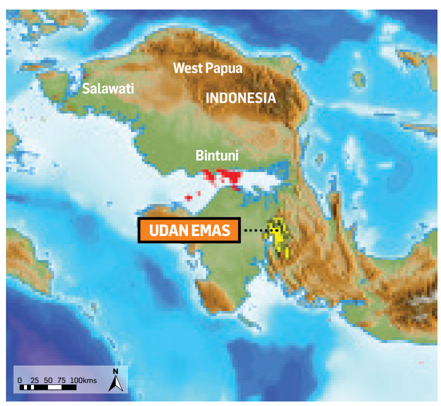
OFFSHORE EAST JAVA, INDONESIA



OIL
GAS



MAKASSAR STRAIT, INDONESIA



ONSHORE WEST PAPUA, INDONESIA

Chairman's Statement

AT THE END OF MY 2017 ANNUAL REPORT STATEMENT, I MADE A REFERENCE TO CHARTERING "CHALLENGING WATERS" AHEAD. 2018 WAS INDEED CHALLENGING AND EXACTLY ONE YEAR LATER IN APRIL 2019, WE CONTINUE TO FACE SIGNIFICANT HURDLES.

Operationally, performance at the Wassana oil field in the Gulf of Thailand experienced some setbacks. Early in 2018, just after the completion of a six-infill well program, we encountered mechanical issues with surface equipment and experienced a loss of integrity in two sections of the main subsea export flowline. The flowline was found to be compromised again in the third quarter and repairs undertaken. These issues, combined with disappointing well productivity, resulted in lower-than-forecast Wassana production for the year and higher operating costs. Overall production in our other producing assets – B8/32 oil and gas complex in the Gulf of Thailand and the Bangora gas field in Block 9 in Bangladesh – was in line with expectations.

We made some progress on our Gulf of Thailand development projects. Modification and refurbishment of the production barge for the Apsara oil development offshore Cambodia commenced in the fourth quarter 2018 in Singapore. For the Rossukon oil development in the G6/48 licence in Thai waters, work on the facilities' front-end engineering and design ("FEED") began in November 2018 and the location for the Rossukon platform was confirmed following a geophysical and geotechnical survey.

We unfortunately recorded one lost time injury in the first quarter of the year. The incident was investigated thoroughly through root cause analysis and preventative measures were put in place alongside procedural retraining. We continue to look for ways to improve our health, safety, security and environment processes and ensure that we are properly monitoring performance and indicators.

Capital structure

Oil prices continued to step up quarter-on-quarter in the first nine months of 2018. However, the fourth quarter saw a return of significant volatility with benchmark Brent crude fluctuating almost US$36 per barrel ("bbl") from a high of US$86.29/bbl in early October to a low of US$50.47/bbl in December. Despite the price swing in the final quarter, our average crude oil and liquids selling price for 2018, was nearly 40% higher than in 2017.

Overall improvements in oil prices led to record revenues for the Group and positive cash flow from operating activities of US$35.3 million was the highest since the 2010 annual period. EBITDAX at US$57.7 million was only surpassed in 2011.

The above notwithstanding, we remained burdened with high non-cash charges from write-offs related to the continuing rationalisation of the portfolio, impairments due to asset performance and ongoing finance costs pursuant to the 2016/2017 restructuring. The material non-cash charges to the profit and loss statement accounted for US$121.1 million of the 2018 loss after tax of US$137.4 million.

We have continued to take all prudent measures to preserve free cash. General and administrative costs have been reduced where possible, including the downsizing of our operations in Indonesia, and capital expenditure has been pared down to requisite expenditure on producing assets and works to progress development projects.

Since the oil price crash at the end of 2014, accumulated losses over the ensuing successive years have resulted in the extensive erosion of book equity and at the end of 2018, Group equity was US$22.7 million.

The Group's year-end carrying value of debt amounted to US$459.1 million and gearing increased to 95.5%. The over-geared balance sheet has put severe pressure on the Group's financial condition and has hampered discussions to obtain financing for our net present value positive development projects despite interest from multiple parties.

The 2018 full-year financial statements have been prepared on a going concern basis. However, the Group's auditors in their assessment of the going concern assumption have necessarily reviewed certain forward looking information of the Group and have concluded that whilst their unqualified audit opinion remains, they view certain material uncertainties relating to going concern. We recognise the challenges ahead and remain committed to evaluate all viable options with our appointed advisors and implement the best course of action to improve our financial condition and provide a more sustainable capital structure.

On behalf of the Board, I would like to thank all stakeholders and DBS Bank Ltd ("DBS") for their continued support in 2018 and 2019, and our employees and contractors for all their efforts throughout the year.

Tan Ek Kia

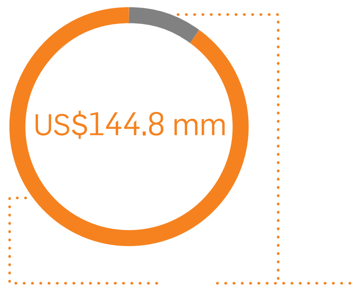
Independent Non-executive Chairman | 1 April 2019

2018 Financial Review

Revenue (US$)

144.8 mm
(2017:140.7)

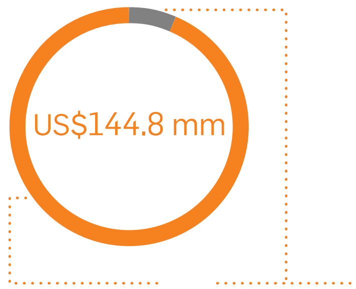
Revenue by Oil to Gas Ratio



Oil & Liquids
US$130.4 mm
90.1%

Gas
US$14.4 mm
9.9%

Revenue by Country



Thailand
US$135.3 mm
93.4%

Bangladesh
US$9.5 mm
6.6%

EBITDAX [1] (US$)

57.7 mm
(2017: 26.8 mm)

Average Lifting Cost (US$)

23.70/boe
(2017: 19.64/boe)

Operating Cost (US$)

79.9 mm
(2017: 82.3 mm)

Loans & Borrowings (US$)
(As at 31 December)

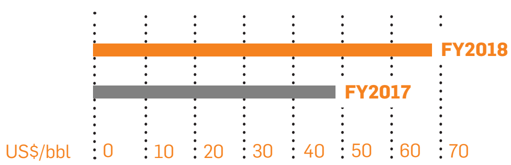
459.1 mm
(2017: 424.6 mm)

Gearing
(As at 31 December)

95.5%
(2017: 73.5%)

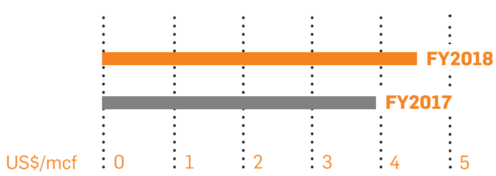
Average Realised Oil & Liquids Sales Price (US$)

68.89/bbl
(2017: 49.26/bbl)



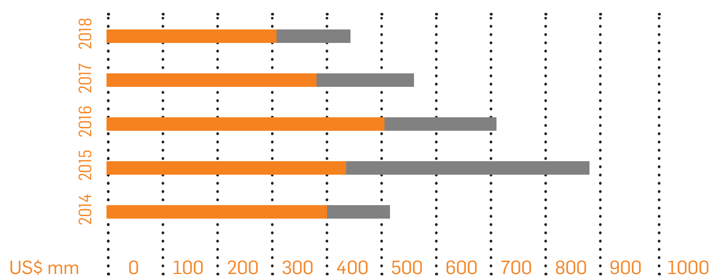
Average Realised Gas Sales Price [2] (US$)

4.58/mcf
(2017: 3.98/mcf)



Oil & Gas Assets (US$) (As at 31 December)

471.7 mm
(2017: 558.5 mm)



Oil and Gas Properties
Exploration and Evaluation Assets

1 Earnings before interest, taxation, depreciation, depletion, amortisation, geological and geophysical expenses and exploration expenses ("EBITDAX"). EBITDAX is a non-IFRS measure

2 Excludes Bangladesh gas at a stable US$2.32/mcf

The global Brent crude oil benchmark averaged US$71.69/bbl in 2018, a 31% increase versus 2017's average (US$54.74/bbl). Prices climbed for the first nine months of 2018 with fluctuations in a US$20.00 band between US$62.00/bbl and US$82.00/bbl. However, a series of geopolitical events, which are ongoing, coupled with surging oil production in the United States, resulted in a swing of almost US$36.00/bbl in Brent prices in the fourth quarter from a high of US$86.29/bbl in October 2018 to a low of US$50.47/bbl in December 2018.

Despite the year-end volatility, the Group realised a 39.9% increase in its average selling oil price in 2018 and a 15.2% improvement in the average gas sales price in Thailand. Consequently, the Group recorded the highest annual revenue since 2009 and the highest EBITDAX since 2011.

Production & revenue

For the year ended 31 December	2018	2017
Sale of crude oil & liquids (US$ million)	130.4	122.8
Sale of gas (US$ million)	14.4	17.9
Revenue (US$ million)	**144.8**	**140.7**
Production volumes[3]		
Oil & liquids (bopd)	5,677	7,066
Gas (mmcfd)	30.1	34.1
Total (boepd)	**10,691**	**12,745**
Average sales price		
Oil & liquids (US$/bbl)	68.89	49.26
Gas – B8/32 & B9A[4] (US$/mcf)	4.58	3.98
Gas – Block 9 (US$/mcf)	2.32	2.32

3 Includes KrisEnergy's working interest share in G11/48 up to 31 May 2018

4 The Tantawan field in B8/32 and the Rajpruek field in B9A permanently ceased operation on 31 October 2017. Abandonment activities are underway before the B9A licence is relinquished

Group working interest production in 2018 averaged 10,691 barrels of oil equivalent per day ("boepd"), 16.1% lower than a year ago. The Group ceased reporting production data from two assets in the Gulf of Thailand, the B9A licence as of 31 October 2017 and the G11/48 concession as of 31 May 2018. On a *pro forma* basis, excluding B9A and G11/48, average working interest production in 2018 from the Group's three producing assets – Block 9, B8/32 and G10/48 – was 7.1% lower at 9,921 boepd (2017: 10,680 boepd) as a result of natural decline and certain production restraints at the Wassana field as well as a 22-day scheduled shutdown in April 2018 at the main Benchamas oil and gas field in B8/32, and prolonged poor weather hampering maintenance and operations at remote locations in the B8/32 fields in August 2018.

The oil and liquids price realised by the Group in 2018 was US$68.89/bbl versus US$49.26/bbl in 2017. The 2018 realised price for B8/32 gas increased 15.2% to US$4.58 per thousand cubic feet ("mcf") (2017: US$3.98/mcf) in line with higher prices for benchmark medium sulphur fuel oil. The realised gas price from the onshore Bangladesh Bangora field in Block 9 was unchanged at US$2.32/mcf.

The higher realised selling prices for oil and liquids, and natural gas in Thailand, boosted 2018 revenue to US$144.8 million, the highest since the Group was established in 2009, with 93.4% of revenue earned in the Gulf of Thailand and the remainder from Block 9 in Bangladesh. Oil accounted for 53.1% of average Group production and 90.1% of total 2018 revenue.

Cost of sales

The Company's cessation of participation in the G11/48 concession as at the end of May 2018 contributed to a 3.0% reduction in overall Group operating costs in 2018 to US$79.9 million (2017: US$82.3 million) although the decrease was partially offset by expenditure on well workovers and equipment maintenance in the Wassana field in G10/48.

In the first quarter of 2018, the Company revised the calculation of average lifting cost to reflect the Group's working interest share of joint-venture operating expenditure incurred versus production in the same period. The Company believes this revised calculation is a better reflection of actual lifting costs over an annual period. In 2018, the average lifting cost was US$23.70 per barrel of oil equivalent ("boe") compared with a revised computed average lifting cost of US$19.64/boe a year ago. The 20.7% increase was attributed to higher operating expenditure related to the Wassana field and overall lower production volumes.

Depreciation, depletion and amortisation ("DD&A") charges in 2018 were 3.0% higher at US$49.8 million (2017: US$48.3 million) as a consequence of a reduction in estimates of proved plus probable ("2P") reserves for the G10/48 asset by Netherland, Sewell & Associates, Inc. ("NSAI") as at 31 December 2018.

For the year ended 31 December	2018	2017
Cost of sales (US$ million)	149.6	144.2
Average lifting cost[5]		
Oil, liquids & gas (US$/boe)	23.70	19.64
Net operating expenditure (US$ million)	92.5	91.4
Total production (boe)[6]	**3,902,390**	**4,651,845**

5 Calculation of average lifting cost has been revised to reflect the Group's working interest share of joint-venture operating expenditure incurred versus production in the same period

6 Includes KrisEnergy's working interest share in G11/48 up to 31 May 2018

Non-cash write-offs, impairments and provisions led to an increase in 2018 in other operating expenses to US$99.0 million (2017: US$64.1 million). The primary non-cash contributors were (i) US$12.9 million write-off related to the expiry of the East Seruway production sharing contract ("PSC") offshore Sumatra, Indonesia; (ii) US$33.4 million write-off related to the Company's intention to relinquish the non-operated Block 120 exploration asset offshore Vietnam; (iii) a non-cash provision of US$15.0 million for the Bala-Balakang PSC in the Makassar Strait, Indonesia, in accordance with IFRS and (iv) a non-cash impairment for G10/48 of US$18.9 million as a result of a lower 2P reserves estimate.

EBITDAX

Earnings before interest, taxation, depreciation, amortisation, geological and geophysical expenses and exploration expenses, considered a global measure of core profitability within the exploration and production sector, more than doubled to US$57.7 million in 2018 (2017: US$26.8 million) primarily due to improved realised selling prices and lower corporate general and administrative expenses.

Loss after tax

Despite 2018's record revenue, the Group recorded a net loss after tax of US$137.4 million. Material non-cash charges to the profit and loss statement amounted to US$121.1 million, comprising: (i) US$49.8 million for DD&A charges; (ii) US$61.4 million for write-offs of exploration assets; (iii) US$18.9 million for impairment of oil and gas properties; (iv) US$20.0 million related to the non-cash accretion of the bond discount related to the S$130 million senior unsecured notes due 2022 ("2022 Notes"), the S$200 million senior unsecured notes due 2023 ("2023 Notes") and 2024 zero coupon notes ("2024 ZCNs"); and (v) write-back of unused decommissioning provisions of US$29.0 million.

Pursuant to the financial restructuring in the first quarter 2017, the Group recognised a one-off non-cash fair value gain on exchange of the 2022 Notes and 2023 Notes amounting to US$73.9 million (the "Notes Exchange Gain") as the 2022 Notes and 2023 Notes were recognised at a discount to par value upon exchange. Each reporting quarter until maturity or redemption of the 2022 Notes and 2023 Notes, the non-cash accretion of the bond discount, computed on the effective interest method in accordance with IFRS, will be charged to the Group's profit and loss as finance costs to offset the Notes Exchange Gain. In addition, non-cash accretion of bond discount on the 2024 ZCNs will be charged to finance costs as the 2024 ZCNs were initially recognised at a discount to par value on issuance in the first quarter 2017.

Loans & borrowings

As at 31 December 2018, total loans and borrowings recognised on the Group's balance sheet amounted to US$459.1 million and the Group's gearing was 95.5%.

On 29 March 2018, DBS extended the tenor of the existing revolving credit facility ("RCF") by two years to 30 June 2020. There were no changes to the existing terms and conditions of the RCF. On 9 April 2018, DBS provided an additional commitment of US$20.0 million (the "Bridge Upsize") under the RCF for a period of up to three months to support the Group's liquidity requirements. Subsequently, DBS and KrisEnergy have entered into the following transactions:

- On 5 July 2018, the Bridge Upsize maturity date was extended for three months to 8 October 2018;
- On 5 October 2018, the Bridge Upsize maturity date was extended for three months to 8 January 2019;
- On 8 January 2019, the Bridge Upsize maturity date was extended for one month to 8 February 2019;
- On 1 February 2019, the Bridge Upsize maturity date was extended for one month to 8 March 2019; and
- On 5 March 2019, the Bridge Upsize maturity date was extended for one month to 8 April 2019.

For the year ended 31 December (US$ million)	2018	2017
2022 Notes	74.3	68.8
2023 Notes	115.4	110.3
2024 ZCNs	66.7	62.8
RCF	148.3	148.3
Bridge Upsize	20.0	–
Unsecured Term Loan	34.4	34.4
Total	**459.1**	**424.6**

Equity

Although the Group benefitted from the general improvement in oil prices in 2018, the consequences of depressed and volatile oil markets from August 2014, coupled with the Group's exposure to interest-bearing debt, have materially and adversely impacted the Group's results of operations and financial condition. As at 31 December 2018, Group total equity declined to US$22.7 million as a result of significant non-cash expenditures relating to finance costs, asset impairments, write-offs and DD&A.

For the year ended 31 December (US$ million)	2018	2017
Share Capital	1.9	1.9
Share Premium	730.3	730.3
Other Reserves	30.7	30.5
Accumulated Losses	(740.2)	(603.0)
Total	**22.7**	**159.7**

Cash

Net cash flow from operating activities in 2018 increased 52.9% to US$35.3 million compared with US$23.1 million in 2017.

Net cash flow used in investing activities was US$45.2 million in 2018 (2017: US$34.5 million). Material movements in capital expenditure in 2018 included (i) infill drilling in G10/48 of US$14.4 million; (ii) infill drilling in the Nong Yao field in G11/48 of US$5.0 million; (iii) US$1.0 million for pre-development work for G6/48; (iv) development activities in Cambodia Block A amounting to US$7.0 million; (v) US$1.1 million for 3D seismic acquisition in Block SS-11, offshore Bangladesh; as well as (vi) ongoing ordinary course of business expenditure in each of Block 9, B8/32 and G10/48.

Net cash flow from financing activities was US$13.8 million in 2018 (2017: US$39.5 million). In 2018, US$20.0 million was drawn from the RCF and coupon payments for the 2022 Notes and 2023 Notes amounted to US$6.2 million.

As at 31 December 2018, the Group's cash and bank balances amounted to US$77.6 million and, after taking into account restricted cash of US$8.3 million, the Group's cash and cash equivalents, including amounts held under joint operations amounted to US$69.3 million. Total unused sources of liquidity excluding amounts held under joint operations amounted to US$32.6 million.

For the year ended 31 December (US$ million)	2018	2017
Net cash flows from operating activities	35.3	23.1
Net cash flows used in investing activities	45.2	34.5
Net cash flows from financing activities	13.8	39.5
Cash and bank balances	**69.3**	**65.6**

Capital expenditure

Group capital expenditure in 2018, excluding non-cash items, amounted to US$56.3 million, significantly below a mid-year forecast of US$96.8 million. The variance resulted from deferral of 2018 infill drilling in the Wassana field to the fourth quarter 2018 and first quarter 2019, a shift in timing into 2019 of some capital expenditures for the Cambodia Block A oil development, and lower than expected costs for a 3D seismic acquisition program in the SS-11 exploration licence in the Bay of Bengal, Bangladesh.

Capital expenditure was primarily spent on:

- Montha-1 exploration well in the G10/48 reservation area and infill drilling in the Wassana oil field;
- Expenditure related to the Apsara oil development in Cambodia Block A;
- Expenditure related to the FEED for the Rossukon oil field development in G6/48;
- Working interest share of the signature bonus for the Andaman II PSC, offshore North Sumatra;
- Working interest share of costs for the non-operated Ca Lang-1X exploration well in Block 120, offshore Vietnam; and
- Working interest share of costs for the 305 sq. km 3D seismic acquisition program in the non-operated SS-11 exploration licence.

Planned capital expenditure for the first quarter 2019 is derived from the work program and budget for each contract area as well as the minimum exploration commitments as required under the terms of the petroleum licences. The following table sets out KrisEnergy's planned capital expenditure for the January-March 2019 period:

For the 3 months ending 31 March 2019 (US$ million)	
Producing assets[5]	15.0
Assets under development[6]	5.6
Non-producing assets[7]	1.7
Total capital expenditure	**22.3**

The Group intends to fund planned capital expenditure through a combination of free cash flow from operations, the RCF, development funding and proceeds or carried interests from select farm-out and asset divestment transactions.

5 Expenditure for assets in production, which include G10/48 and Block 9

6 Expenditure for assets under development, which include Cambodia Block A, the production barge and G6/48

7 Expenditure for exploration assets, which include SS-11 and the Group's assets in Indonesia and Vietnam

Fiscal Terms

THE PETROLEUM LICENCES IN WHICH WE HAVE INTERESTS CONTAIN THE TERMS OF OUR CONCESSIONS AS AGREED BETWEEN THE PARTICIPANTS AND THE RELEVANT HOST GOVERNMENT.
THE ECONOMIC TERMS OF THESE LICENCES, COMMONLY KNOWN AS FISCAL TERMS, VARY DEPENDING ON JURISDICTION.

Bangladesh

The table sets out the material fiscal terms of our Bangladesh assets.

	Block 9	SS-11
Domestic Market Obligation ("DOM") for Oil	With six months' prior written notice, Petrobangla may require contractor to provide its *pro rata* share of oil, up to 25.0% of its share of profit oil, for domestic consumption.	With six months' prior written notice, Petrobangla may require contractor to provide its *pro rata* share of oil, up to 80.0% of its share of profit oil, for domestic consumption.
DMO Price for Oil	15.0% discount to fair market value.	15.0% discount to fair market value.
DMO for Gas	Contractor must first offer all its share of gas to Petrobangla and its affiliates. If Petrobangla or its affiliates do not purchase the gas within six months of contractor's submission of an evaluation report, contractor is free to find a market outlet within Bangladesh.	Contractor must first offer all its share of gas to Petrobangla and its affiliates. If Petrobangla or its affiliates does not purchase the gas within six months of contractor's submission of an evaluation report, contractor is free to find a market outlet within Bangladesh.
DMO Price for Gas	Price of gas sold to Petrobangla and its affiliates is set at 75.0% of the average for each calendar quarter of Platt's Oilgram quotations of High Sulphur Fuel Oil 180 CST, free-on-board ("FOB") Singapore with a floor price of US$70 per metric tonne and ceiling price of US$120 per metric tonne. Price of gas sold to Petrobangla is subject to a further 1.0% discount. Price of gas sold to third parties shall be equal to or greater than the pricing formula described above.	Price of gas sold to Petrobangla and its affiliates is set at 75.0% of the average for each calendar quarter of Asian Petroleum Price Index quotations of High Sulphur Fuel Oil 180 CST, FOB Singapore with a floor price of US$100 per metric tonne and ceiling price of US$200 per metric tonne. Price of gas sold to Petrobangla is subject to a further 1.0% discount. Price of gas sold to third parties shall be equal to or greater than the pricing formula described above.
Cost Recovery Limit		
Oil	Up to 40.0% per calendar year of all oil produced and saved from the contract area and not used in petroleum operations.	Up to 55.0% per calendar year of all oil produced and saved from the contract area and not used in petroleum operations.
Gas	Up to 45.0% per calendar year of all gas produced and saved from the contract area and not used in petroleum operations.	Up to 55.0% per calendar year of all gas produced and saved from the contract area and not used in petroleum operations.

	During Cost Recovery	After Cost Recovery	
Profit Oil Split (to Contractor)			
Up to 10,000 bopd	33.0%	30.0%	–
Portion Over 10,000 & Up to 25,000 bopd	30.0%	25.0%	–
Portion Over 25,000 & Up to 50,000 bopd	25.0%	20.0%	–
Portion Over 50,000 & Up to 100,000 bopd	20.0%	15.0%	–
Portion Over 100,000 bopd	17.0%	10.0%	–
Profit Gas Split (to Contractor)			
Up to 75 mmcfd	39.0%	34.0%	45.0%
Portion Over 75 & Up to 150 mmcfd	39.0%	34.0%	40.0%
Portion Over 150 & Up to 250 mmcfd	34.0%	27.5%	35.0%
Portion Over 250 & Up to 300 mmcfd	34.0%	27.5%	30.0%
Portion Over 300 & Up to 400 mmcfd	27.5%	22.0%	30.0%
Portion Over 400 & Up to 450 mmcfd	27.5%	22.0%	25.0%
Portion Over 450 & Up to 600 mmcfd	25.0%	17.5%	25.0%
Portion Over 600 mmcfd	18.0%	15.0%	20.0%

	Block 9		SS-11
	During Cost Recovery	After Cost Recovery	
Profit Condensate/ Liquids (to Contractor)			
Up to 3,000 boepd	35.0%	30.0%	–
Portion Over 3,000 & Up to 6,000 boepd	32.0%	27.0%	–
Portion Over 6,000 & Up to 10,000 boepd	28.0%	25.0%	–
Portion Over 10,000 & Up to 15,000 boepd	25.0%	20.0%	–
Portion Over 15,000 boepd	20.0%	15.0%	–
Profit Oil and Condensate/ Liquids (to Contractor)			
Up to 5,000 boepd	–	–	45.0%
Portion Over 5,000 & Up to 12,500 boepd	–	–	42.5%
Portion Over 12,500 & Up to 25,000 boepd	–	–	40.0%
Portion Over 25,000 & Up to 40,000 boepd	–	–	35.0%
Portion Over 40,000 & Up to 65,000 boepd	–	–	30.0%
Portion Over 65,000 & Up to 100,000 boepd	–	–	25.0%
Portion Over 100,000 boepd	–	–	20.0%
		General	General
Production Bonus Payments			
Within 30 Days of First Commercial Discovery		US$1mm	US$3mm
		Oil	Oil
Upon Daily Average of 10,000 bopd for 30 Consecutive Days		US$1mm	US$0.5mm
Upon Daily Average of 20,000 bopd for 30 Consecutive Days		US$1mm	US$1mm
Upon Daily Average of 30,000 bopd for 30 Consecutive Days		US$1mm	US$2mm
Upon Daily Average of 40,000 bopd for 30 Consecutive Days		US$2mm	US$2.5mm
Upon Daily Average of 50,000 bopd for 30 Consecutive Days		US$2mm	US$3mm
Upon Daily Average of 100,000 bopd for 30 Consecutive Days		US$2mm	US$4mm
		Gas	Gas
Upon Daily Average of 75 mmcfd for 30 Consecutive Days		US$1mm	US$0.5mm
Upon Daily Average of 150 mmcfd for 30 Consecutive Days		US$1mm	US$1mm
Upon Daily Average of 225 mmcfd for 30 Consecutive Days		US$1mm	US$2mm
Upon Daily Average of 300 mmcfd for 30 Consecutive Days		US$2mm	US$2.5mm
Upon Daily Average of 375 mmcfd for 30 Consecutive Days		US$2mm	US$3mm
Upon Daily Average of 450 mmcfd for 30 Consecutive Days		–	US$4mm
Upon Daily Average of 600 mmcfd for 30 Consecutive Days		US$5mm	US$6mm
Income Tax		All Bangladesh income tax levied on petroleum operations are borne and discharged by Petrobangla.	All Bangladesh income tax levied on petroleum operations are borne and discharged by the contractor.
Bangladesh Participation Option		None	None

Cambodia

The table sets out the material fiscal terms of Cambodia Block A.

	Block A	
Royalty	12.5% of production	
Cost Recovery Petroleum	85.0% of production for first five years from date of first commercial production, and 70.0% of production for the period thereafter	
Allocation of Remaining Oil (to Contractor) (average annual production)	Up to 10,000 bopd	58.0%
	In excess of 10,000 – 25,000 bopd	53.0%
	Portion over 25,000 and up to 50,000 bopd	48.0%
	Portion over 50,000 bopd	38.0%
Allocation of Remaining Gas (To Contractor)	65.0%	
Income Tax (Not Payable on the Royalty Petroleum or Cost Recovery Petroleum)	25.0% for five years from first year of taxable income, and 30.0% thereafter.	
Export Tax	2.0%	
Production Bonus Payment	None	
Excess Profit Tax ("EPT")	**Excess Profit Ratio**	**EPT Rate**
	0.00 – 1.30	0.0%
	1.30 – 1.60	10.0%
	1.60 – 2.00	20.0%
	2.00 – 2.50	30.0%
	2.50 – 3.00	30.0%
	over – 3.00	30.0%
Annual Surface Rental Fee	US$500 per sq. km of unrelinquished contract area from effective date.	
Ministry of Mines and Energy ("MME") Option	5.0% participating interest held by General Department of State Property and Non Tax Revenue ("GDSPNTR") of the Ministry of Economy and Finance. Petroleum operations costs associated with GDSPNTR's 5.0% participating interest will be carried by the remaining holder(s) of the 95.0% participating interest in the block and reimbursed out of GDSPNTR's share of revenues from commercial production.	

Indonesia

The table sets out the material fiscal terms of our Indonesian assets.

1 Pending relinquishment

	Bulu	East Seruway[1]	Sakti	Bala-balakang	Udan Emas
First Tranche Petroleum ("FTP") (Oil and Gas): (as % of Total Petroleum Production)					
	10.0%	20.0%	20.0%	20.0%	20.0%
Effective Tax Rate	44.0%	44.0%	44.0%	44.0%	44.0%
DMO For Oil	25.0%	25.0%	25.0%	25.0%	25.0%
DMO for Gas	25.0%	25.0%	25.0%	25.0%	25.0%
DMO Price for Oil (% of Market Price)	25.0%	25.0%	25.0%	25.0%	25.0%
DMO Price for Gas (% of Market Price)	100.0%	100.0%	100.0%	100.0%	100.0%
Pre-Tax Profit Oil Split to Contractor	35.7%	26.8%	41.7%	58.3%	58.3%
Pre-Tax Profit Gas Split to Contractor	62.5%	53.6%	58.3%	66.7%	66.7%
Production Bonus Payments Upon Cumulative Production Having Reached:					
25 mmboe	–	US$1mm	US$1mm	US$1mm	US$1mm
50 mmboe	US$500,000	US$1mm	US$1.5mm	US$1.5mm	US$1.5mm
75 mmboe	US$1mm	US$1mm	US$2mm	US$2mm	US$2mm
100 mmboe	–	–	–	–	–
125 mmboe	US$2mm	–	–	–	–
Indonesian Participation Option	10.0%	10.0%	10.0%	10.0%	10.0%
ACEH Participation Option	–	–	–	–	–
Local Community Fund Contribution	–	–	–	–	–

	Andaman II	
Pre-Tax Gross Profit Split to Contractor		
	Oil	**Gas**
Base Split	43.0%	48.0%
Variable Split	Not fixed; to be determined at a future stage (dependent on variable factors)	
Progressive Split	Not fixed; to be determined at a future stage (dependent on variable factors)	
Contractor Tax Regime Rate	40.0%	

Thailand

The table sets out the material fiscal terms of our Thai assets.

	B9A[2]	B8/32[2], G6/48, G10/48 & G11/48[3]	
Royalty (as % of the Value of Petroleum Sold or Disposed in Each Month)	12.5%	0 – 60,000 barrels	5.0%
		60,000 – 150,000 barrels	6.2%
		150,001 – 300,000 barrels	10.0%
		300,001 – 600,000 barrels	12.5%
		Over 600,000 barrels	15.0%
Income Tax Rate	50.0%		50.0%
Annual Surface Reservation Fee	THB 4,000 per sq. km per year		Payable at various rates
Special Remuneratory Benefit	None	Payable at the end of each fiscal year in various rates based on the profit earned during the year up to a maximum payment of 75.0% of the profit earned.	

	B9A[2]	B8/32	G6/48	G10/48	G11/48[3]
Production Bonus Payment	Fully discharged	Fully discharged	US$0.3 million payable within 30 days from day total production from the contract area first averages 10,000 boepd for 90 consecutive days	US$0.5 million payable within 30 days from day total production from the contract area first averages 20,000 boepd for 30 consecutive days	US$0.5 million payable within 30 days from day total production from the contract area first averages 20,000 boepd for 30 consecutive days
Thai Participant Option	None	None	None	10.0%	10.0%, discharged

2 The Tantawan field in B8/32 and the Rajpruek field in B9A permanently ceased operation on 31 October 2017. Abandonment activities are underway before the B9A licence is relinquished

3 KrisEnergy ceased participation in the G11/48 licence as of 31 May 2018

Vietnam

The table sets out the material fiscal terms of our Vietnam assets.

4 Pending relinquishment

	Block 115/09	Block 120[4]
Royalty on Oil (bopd)	7.0% / 9.0% / 11.0% / 13.0% / 18.0% / 23.0% 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000	4.0% / 6.0% / 8.0% / 10.0% / 15.0% / 20.0% 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000
Royalty on Gas (mmcfd)	0.0% / 3.0% / 6.0% 0 / 5 / 10	0.0% / 3.0% / 6.0% 0 / 5 / 10
Cost Recovery Limit	70.0% of gross reserves	70.0% of gross reserves
Pre-Tax Profit Oil Split (to Contractor)	75.0% / 70.0% / 65.0% / 60.0% / 55.0% / 50.0% 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000	40.0% / 35.0% / 30.0% / 25.0% / 20.0% / 15.0% 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000
Pre-Tax Profit Gas Split (to Contractor)	77.0% / 70.0% / 60.0% / 50.0% / 50.0% 0 / 5 / 10 / 15 / 20	50.0% / 47.5% / 45.0% / 42.5% / 40.0% 0 / 5 / 10 / 15 / 20
Income Tax Rate	32.0% / 32.0% / 32.0% 0 / 12 / 24	0.0% / 16.0% / 32.0% 0 / 12 / 24
Oil Export Duty	10.0%	4.0%
Production Bonus Payments		
General		
Within 30 Days of First Commercial Discovery	US$1mm	US$2mm
Within 30 Days of First Commercial Production	US$1mm	US$2mm
Oil (bopd) 30 Consecutive Days	US$1mm / US$2mm / US$3mm / US$4mm / US$5mm 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000	US$2mm / US$3mm / US$5mm / US$7mm / US$10mm 0 / 20,000 / 50,000 / 75,000 / 100,000 / 150,000
Gas (mmcfd) 30 consecutive Days	US$1mm / US$1mm / US$1mm 0 / 5 / 10 / 15	US$2mm / US$3mm / US$4mm 0 / 5 / 10 / 15
PetroVietnam Option	20.0%	20.0%

The table sets out certain information regarding our oil and gas assets as at 1 April 2019.

Country/ Asset Name	Effective Interest (%)	Status[1]	Effective Date	Licence Expiry Date	Exploration Period	Production Area	Production Permit Expiry Date	Licence Area (sq. km)	Type of Mineral Oil or Gas Deposit	Licence Type
Bangladesh										
Block 9	30.0	Production & development unclarified	11 April 2001	26 August 2033	–	Bangora	26 August 2033[2]	1, 770	Gas / Condensate	PSC
SS-11	45.0	Exploration	12 March 2014	See Note 2	12 March 2014 to 11 March 2021	–	–	4,475	Oil/Gas	PSC
Cambodia										
Block A	95.0	Near production	23 August 2017	22 August 2042	23 August 2017 to 22 August 2024	Apsara	22 August 2042	3,083	Oil	Petroleum Agreement
Indonesia										
Bulu	42.5	Near production	14 October 2003	13 October 2033	–	Lengo	13 October 2033	697	Gas	PSC
East Seruway	100.0	Exploration[3]	13 November 2008	12 November 2038	13 November 2008 to 12 June 2020	–	–	1,172	Oil/Gas	PSC
Sakti	95.0	Development unclarified	26 February 2014	25 February 2044	26 February 2014 to 25 February 2020[4]	–	–	3,719	Oil/Gas	PSC
Bala-Balakang	85.0	Development unclarified	19 December 2011	18 December 2041	19 December 2011 to 18 December 2021[4]	–	–	838	Gas	PSC
Udan Emas	100.0	Exploration	20 July 2012	19 July 2042	20 July 2012 to 19 July 2022[4]	–	–	1,070	Gas	PSC
Andaman II	30.0	Exploration	5 April 2018	4 April 2048	5 April 2018 to 4 April 2024	–	–	7,400	Oil/Gas	Gross Split PSC
Thailand										
B8/32	4.6345	Production	1 August 1991	31 July 2030[5]	–	Tantawan[7]	31 July 2030[6]	1,992	Oil/Gas	Tax/ Royalty
						Benchamas South and Pakarong	31 July 2030[6]			
						Maliwan	31 July 2030[6]			
						North Jarmjuree	31 July 2030[6]			
						North Benchamas	31 July 2030[6]			
						Chaba	31 July 2030[6]			
B9A	4.6345	Production[7]	17 July 2003	16 July 2041[5]	–	Rajpruek[7]	16 July 2041[6]	80	Oil/Gas	Tax/ Royalty
G6/48		Near production & development unclarified	8 January 2007	See Note 5	8 January 2007 to 7 January 2021[4]	Rossukon	7 January 2036[6]	284	Oil/Gas	Tax/ Royalty
Production area	100.0[8]									
Reservation area	30.0									
G10/48	89.0	Production & development unclarified	8 December 2006	See Note 5	8 December 2006 to 7 December 2020[4]	Wassana	7 December 2035[6]	1,525	Oil	Tax/ Royalty
Vietnam										
Block 115/09	100.0	Exploration	31 March 2014	30 March 2044	31 March 2014 to 30 March 2020[4]	–	–	7,382	Oil/Gas	PSC
Block 120	33.33	Exploration[9]	23 January 2009	22 January 2039	23 January 2009 to 22 January 2019[4]	–	–	6,869	Oil/Gas	PSC

NOTES:

1 Each of our contract areas also holds exploration prospects and leads
2 Production permits will be valid for 25 years with an extension period of up to five years
3 The East Seruway PSC is pending relinquishment
4 Exploration period may be extended with the approval of the host government
5 Licence expiry dates can be extended if host government grants extension of exploration period or production permit
6 Production permits are valid for 20 years with an extension period of up to 10 years
7 The Tantawan field in B8/32 and the Rajpruek field in B9A permanently ceased operation on 31 October 2017. Abandonment activities are underway before the B9A licence is relinquished
8 As of 18 February 2019, KrisEnergy has 100.0% working interest in the Exclusive Operation of the Rossukon Field development plan
9 The Block 120 PSC is pending relinquishment

2018 Technical Review

OUR LIMITED FINANCIAL RESOURCES WERE ALLOCATED TO PRODUCING ASSETS AND THE PROGRESSION OF DEVELOPMENT PROJECTS IN 2018, WHILE EXPLORATION ACTIVITIES WERE REDUCED TO A MINIMUM OF COMMITTED WORK IN AN EFFORT TO PRESERVE FREE CASH FLOW.

Environment, health, safety and security ("EHSS") remained a priority across the organisation and Group operations recorded 1,614,865 man-hours in 2018 with one lost time injury in March 2018, when a worker on board the *MOPU Ingenium* in the Wassana field sustained an injury to a finger during regular maintenance to a pump. Following the incident, a thorough investigation was held to address the root cause and corrective and preventive actions were implemented along with retraining in procedural best practice.

The Company renewed its OHSAS 18001 / ISO 45001 and ISO 14001 certifications for offices in Dhaka and Singapore, as well as at the Bangora gas field operation in Block 9. Work is underway to extend these accreditations to KrisEnergy-operated fields in the Gulf of Thailand.

We have been mindful of security issues in some of our host countries and we continuously review security alert levels and the appropriateness of arrangements in place and our internal controls. 2018 passed without any security incident in KrisEnergy's operations.

Portfolio management

As part of the revised business plan, set out and effective from the fourth quarter of 2016, portfolio rationalisation continued throughout 2018. The Company ceased participation in the non-operated G11/48 licence, containing the Nong Yao oil field in the Gulf of Thailand, and the Block A Aceh PSC onshore Aceh, Indonesia, and relinquished the East Seruway PSC, offshore Sumatra in Indonesia following the expiry of the PSC in June 2018. In 2019, it is the Company's intention to relinquish the non-operated Block 120 exploration licence offshore Vietnam.

As at 1 April 2019, KrisEnergy's portfolio comprised three producing assets – B8/32 and G10/48 in the Gulf of Thailand and Block 9 onshore Bangladesh; three development projects – the Apsara oil field in Cambodia Block A and the Rossukon oil field in G6/48, both in the Gulf of Thailand, and the Lengo gas field in the Bulu PSC, offshore East Java; and seven contract areas in various stages of appraisal or exploration[1]. KrisEnergy operates nine of the 13 contract areas.

1 Oil and gas production in B9A in the Gulf of Thailand terminated in October 2017 and abandonment is underway before the licence is relinquished

Given the Company's financial condition as at 31 December 2018, it is likely that further portfolio rationalisation will be undertaken in the future.

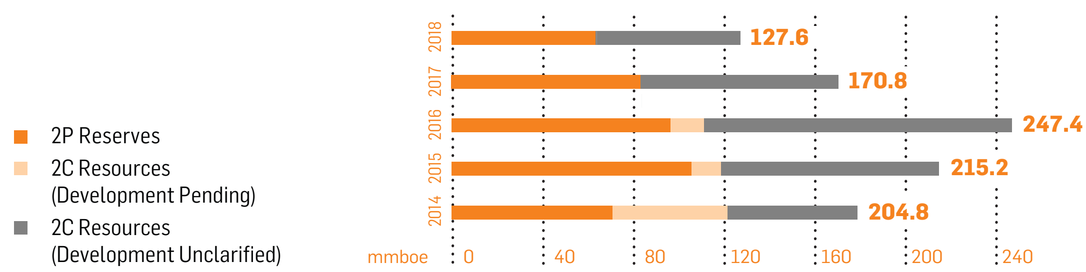
2P reserves & 2C resources

Year-end 2018 working interest 2P reserves were estimated by NSAI at 63.5 million barrels of oil equivalent ("mmboe") as at 31 December 2018 versus 83.5 mmboe as at 31 December 2017. More than half of the decrease – 11.2 mmboe – resulted from the Company ceasing participation in the Block A Aceh PSC and to a lesser extent the G11/48 licence.

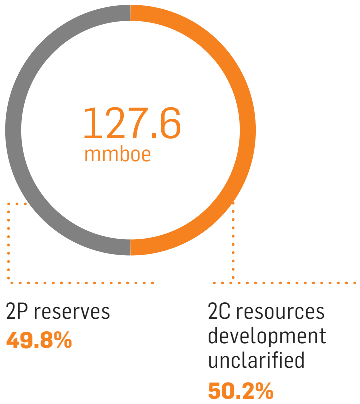
Reserves assigned to the G10/48 licence in the Gulf of Thailand were reduced by 53% to 5.7 mmboe due to 2018 production and lower well recovery. Assessments for 2P reserves also decreased for B8/32 and Block 9 due to 2018 production and, in the case of B8/32, assumptions of reduced future infill drilling.

NSAI recognised best estimate 2C resources in the development unclarified category of 64.1 mmboe as at 31 December 2018, a 27% drop from 2017 as a result of the removal of contribution from Block A Aceh, which accounted for 27.9 mmboe. Gains in 2C resources of a combined 5.1 mmboe were recorded for G10/48 and G6/48, which contains the Rossukon oil development project in the Gulf of Thailand.

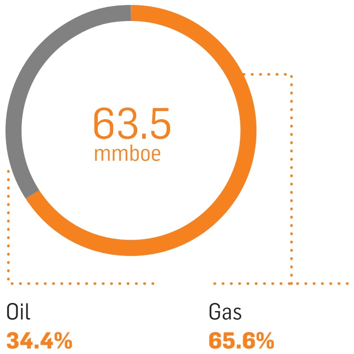
2P reserves and 2C resources



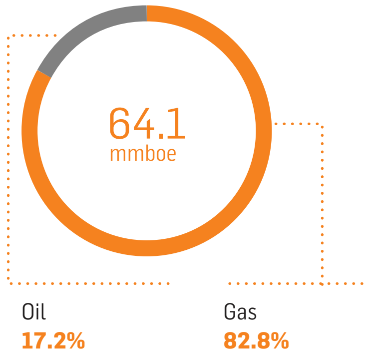
Total 2P reserves and 2C resources[2] (mmboe)



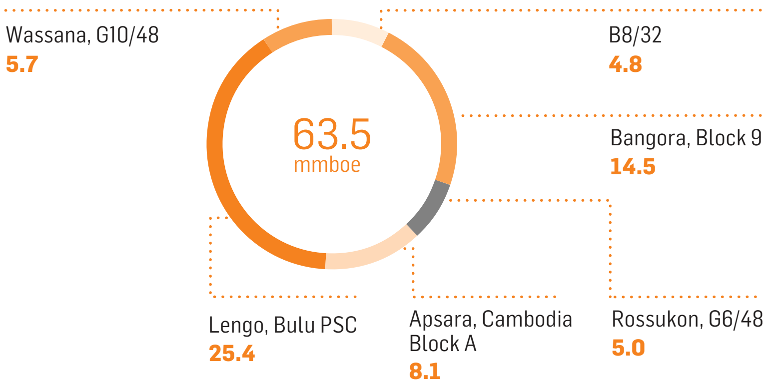
2P reserves oil vs gas (mmboe)



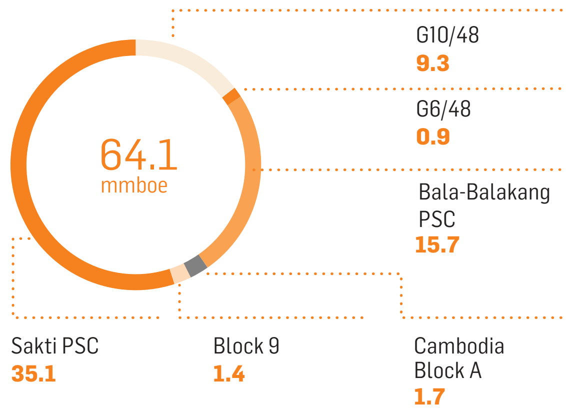
2C resources oil vs gas (mmboe)



Production/near production 2P reserves (mmboe)



Development unclarified 2C resources[3] (mmboe)



2 2P reserves refer to proved plus probable reserves and 2C resources refer to best estimate contingent resources in accordance with the definitions and guidelines of the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers

3 Development unclarified refers to a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay

Capital expenditure

Group capital expenditure in 2018 amounted to US$56.3 million, which was primarily spent on infill drilling in the G10/48 and G11/48[4] producing fields, development activities in the Apsara oil project in Cambodian Block A, expenditure related to the FEED for the Rossukon oil development in G6/48, one exploration well each in G10/48 and Block 120, and a 3D seismic acquisition program in the SS-11 exploration licence, offshore Bangladesh.

4 KrisEnergy ceased participation in the G11/48 licence as of 31 May 2018

Production & infill drilling

The Group's average working interest production in 2018 was 10,691 boepd, 16.1% lower than in 2017, primarily due to reduced contribution from two licences in the Gulf of Thailand, G11/48 and B9A. The B9A licence permanently terminated oil and gas production in October 2017 and KrisEnergy ceased participation in the G11/48 licence as of 31 May 2018.

On a *pro forma* basis, excluding 2017 volumes for G11/48 and B9A, the Group's remaining three assets – Block 9, G10/48 and B8/32 – produced at an average rate of 9,921 boepd, approximately 7.0% below 2017 levels as a result of natural decline and certain restraints at the Wassana field throughout the year as well as a 22-day scheduled shutdown in April 2018 at the main Benchamas oil and gas field in B8/32, and prolonged poor weather hampering maintenance and operations at remote locations in the B8/32 fields in August 2018.

Block 9, Bangora gas field

Intervention work in the KrisEnergy-operated Bangora gas field in November 2018 to open three new sands – A, B, C – and to close sand D at the B-5 well doubled the well's production rate to approximately 40 million cubic feet per day ("mmcfd"). For the year, gross Bangora production averaged 87.2 mmcfd and 260 barrels of condensate per day and KrisEnergy's working interest share of production for year was 4,439 boepd. The field underwent scheduled annual maintenance from 22 to 25 August 2018 with production resuming 29 hours ahead of initial estimates. Further minor works on compressors were performed throughout September 2018.

G10/48, Wassana oil field

Gross production in the KrisEnergy-operated Wassana oil field in the Gulf of Thailand averaged 4,455 barrels of oil per day ("bopd") in 2018, marginally higher than 4,377 bopd in 2017, and the Group's working interest share of production was 3,965 bopd. Liftings of Wassana crude oil increased from six in 2017 to eight in 2018.

Production was constrained for most of the year due to integrity issues with the main 6-inch subsea crude flowline running between the mobile offshore production unit ("MOPU") and the floating storage and offloading vessel ("FSO") and also due to mechanical issues with pumps.

In February and September 2018, inspection of the 6-inch flowline detected damage in two sections. Remedial work required the line to be shut-in and crude oil export to the FSO transferred to an existing 4-inch flowline. The damaged sections were replaced and crude oil export was permanently switched to the 4-inch line with water return for reinjection from the FSO to the MOPU through the 6-inch line. Optimisation of the operational temperature/pressure parameters within the flowlines has resulted in no further anomalies detected to date on the flowlines.

Other maintenance works in 2018 included the replacement and upgrading of pumps and debottlenecking of the water separation capacity in preparation for the anticipated increase in crude oil handling capabilities resulting from well workovers and infill drilling. A planned shutdown was undertaken 27-28 August 2018 for the installation and commissioning of an additional 450-kilowatt emergency diesel generator. A second scheduled shutdown occurred on 26-27 November 2018 to allow for the approach and positioning of the *Mist* jack-up rig for the 2018 infill drilling program.

G10/48 drilling

Three new infill wells – A-18H, A-19H and A-23H – from the 2017 infill drilling program went on line in January 2018, and together with the restart of the original A-10H well, Wassana production increased to more than 7,100 bopd at the beginning of February 2018 prior to integrity issues with the 6-inch flowline.

Following completion of the 2017 infill program in February 2018, the *PV Drilling I* jack-up rig was mobilised to the north of the Wassana facilities to drill the Wassana-4 appraisal well in an extension of the main field. Wassana-4 reached a total depth at 5,960 feet measured depth ("MD") (-5,764 feet true vertical depth subsea ("TVDSS")) and encountered net vertical oil pay of 31 feet true vertical thickness ("TVT"). The well was sidetracked, Wassana-4ST, to a total depth 5,687 feet MD (-5,561 feet TVDSS) and encountered 67 feet TVT of net oil pay. Preliminary results indicated the potential justification for commercial development of the Wassana North Satellite tied back to the existing Wassana facilities.

Following the success of the Wassana-4 and Wassana-4ST appraisal wells, the 2018 infill drilling program was designed to include two wells within the main production area plus an extended reach well out to the Wassana North Satellite area. The drilling campaign commenced with the Montha-1 exploration well approximately 15 km westnorthwest of the Wassana field within the G10/48 reservation area.

The *Mist* jack-up rig commenced drilling of the Montha-1 exploration well on 12 November 2018. Water depth at the well location is 172 feet (52.4 metres). On 23 November 2018, the well reached total depth at 10,396 feet MD rotary kelly bushing (-9,138 feet TVDSS). No significant hydrocarbon shows were detected in the target reservoirs and the well was plugged and abandoned.

The 2018 Wassana workover and infill drilling campaign began on 28 November 2018 with the workover of well A-23H to change the electrical submersible pump. Operations were suspended on 2 January 2019 along with a complete shutdown of Wassana production, the evacuation of all crew and a decoupling of the FSO from its mooring as a precaution due to Tropical Storm Pabuk. All crew and equipment returned to the Wassana field location without incident on 8 January 2019 and operations restarted.

The following summarises the 2018 G10/48 drilling program:

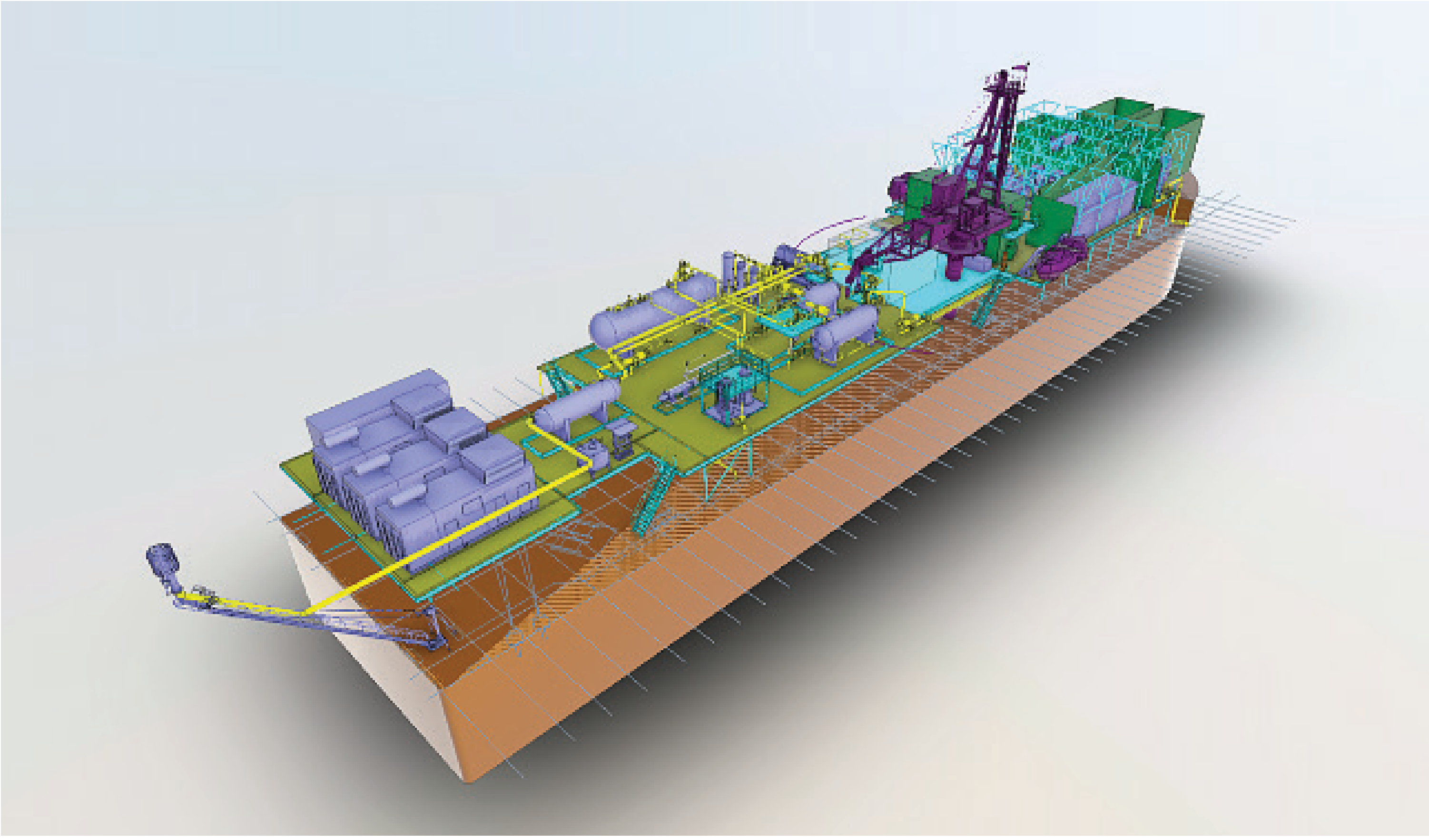
- Existing wells A-17D, A-10H and A-06D were plugged and abandoned;
- Workovers were performed on A-23H, A-03H and A-25H;
- Drilling of A-30H extended reach well commenced on 10 January 2019 and reached total depth at 13,662 feet MD (-5,226 feet TVDSS). A-30H was completed on 4 February 2019 and was put on stream at a rate of 920 bopd;
- Drilling of A-26H infill well commenced on 21 January 2019 and reached total depth at 8,998 feet MD (-5,162 feet TVDSS). A-26H was completed on 9 February 2019 and was put on stream at a rate of 570 bopd;
- Drilling of A-27H infill well commenced on 29 December 2018 and reached total depth at 9,925 feet MD (-5,413 feet TVDSS). A-27H was completed on 14 February 2019 and was put on stream at a rate of 1,000 bopd; and
- The *Mist* rig demobilised from the Wassana field on 19 February 2019.

On 30 January 2019, the Department of Mineral Fuels in Thailand approved KrisEnergy's proposal for the relinquishment of a portion of the reservation area in the G10/48 licence. The reservation area was reduced to 114 sq. km from 1,392 sq. km. The Wassana production area was unchanged at 132 sq. km.

B8/32, Gulf of Thailand

Average gross production in 2018 in the non-operated B8/32 oil and gas complex in the Gulf of Thailand was 18,626 bopd and 84.6 mmcfd, or the equivalent of 32,724 boepd. KrisEnergy's working interest production for the year was 1,517 boepd.

Production was impacted by a 22-day planned shutdown of the main Benchamas field in April 2018 to install a new FSO vessel and an extended bad weather period in August 2018, which limited movement between remote platforms and therefore delayed reservoir zonal perforations and maintenance of gas compressors and generator systems. Crude oil production dipped to approximately 15,000 bopd during the August period but recovered in late September/early October 2018 to around 20,000 bopd



3D CAD model of the Cambodia Block A production barge

Below: The production barge in drydock in Singapore

B8/32 drilling

A 13-well infill well drilling campaign commenced in August 2018. Seven infill wells were drilled on the BEWS platform and six infill wells were drilled on the CBWA platform. All 13 wells were completed and put on production in December 2018.

The Chaba platform resumed operations in late February 2019 following a two-week scheduled maintenance stoppage at the Platong gathering facility. Production at Chaba resumed at approximately 4,650 bopd versus 2,500 bopd prior to the six CBWA infill wells going on stream.

The 2019 infill drilling program commenced earlier than scheduled on 4 December 2018 with two jack-up rigs in operation for the 36-well program. Drilling was suspended on 31 December 2018 due to Tropical Storm Pabuk and restarted on 6 January 2019:

- 10 wells at the MAWD platform and six wells at the BEWU platform were completed in February 2019 and were on production in March 2019; and
- 20 wells associated with platforms MAWC (12 wells) and BEWG (8 wells) are scheduled to be completed and on stream by the end of July 2019.

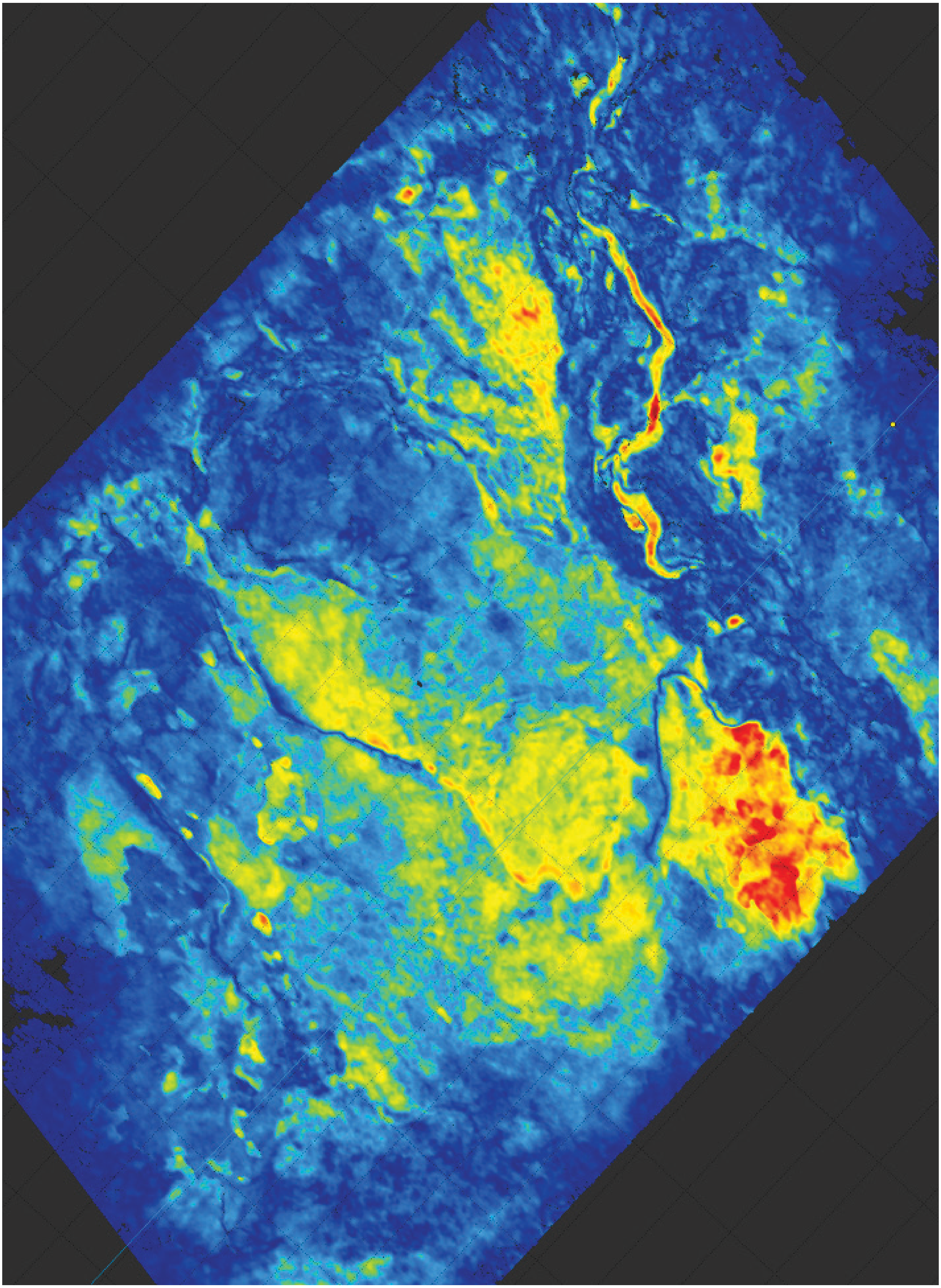
Production barge

KrisEnergy's wholly-owned subsidiary SJ Production Barge Ltd, contracted Keppel Shipyard Ltd ("Keppel Shipyard") in October 2018 for the modification and upgrading of a production barge for the Apsara oil development in the Cambodia Block A concession in the Gulf of Thailand, the first hydrocarbon project for the Kingdom of Cambodia.

The production barge is one of three main components of the Phase 1A Apsara oil project, the others being the minimum facilities platform and integrated drilling services. Keppel Shipyard's scope of work on the production barge includes enhancement of production facilities, installation of a power generation module, Electrical House, new accommodation units and other refurbishment works.

Decommissioning of the topsides commenced on the barge in the fourth quarter 2018 at Keppel Shipyard's Benoi facilities. The vessel was moved to the Gul drydock in March 2019 for steel life extension works before installation of accommodation units and helipad. Full modification of the production barge is scheduled to be completed by October 2019.

KrisEnergy is the operator of Cambodia Block A, which covers 3,083 sq. km over the Khmer Basin in the Gulf of Thailand where water depths range between 50 metres and 80 metres. Phase 1A of the Apsara development consists of a single unmanned minimum facility producing to a moored production barge. Produced crude oil will be sent via a 1.5 km pipeline for storage to a permanently moored FSO.



FEED work

Technip FMC Thailand was awarded in November 2018 the contract for the FEED for the KrisEnergy-operated Rossukon oil development, located in the G6/48 licence in the Gulf of Thailand. In parallel, the final location of the Rossukon A platform was confirmed following a geophysical and geotechnical survey.

The Rossukon series of discoveries is located over the Karawake Basin to the north of the G10/48 licence. The Company drilled two exploration wells and two planned sidetrack wells in the Rossukon area in the first half of 2015. Each well encountered oil and gas, adding to volumes from the original Rossukon discovery made in 2009.

The Petroleum Committee of Thailand approved on 28 December 2018 a two-year extension of the four-year period to commence petroleum production in G6/48 until November 2021.

On 17 August 2018, KrisEnergy (Gulf of Thailand) Limited ("KEGOT"), a wholly-owned subsidiary and operator of the G6/48 licence issued to each of the joint-venture partners, Northern Gulf Petroleum Pte Ltd ("Northern Gulf") and MP G6 (Thailand) Limited ("MP G6"), a notice to conduct the field development plan in the Rossukon production area as an Exclusive Operation. All joint-venture partners were given 60 days to respond to the notice. On 20 October 2018, KEGOT informed the joint-venture partners, that under the Joint Operating Agreement, each of KEGOT and Northern Gulf were electing to take their *pro rata* share of the Exclusive Operation. KEGOT's working interest in the Rossukon production area therefore increased to 43.0% from 30.0% and Northern Gulf's working interest increased to 57.0% from 40.0%. Working interest in the G6/48 reservation area remained unchanged with KEGOT holding 30.0%, Northern Gulf 40.0% and MP G6 with 30.0%.

Subsequently on 18 February 2019, KEGOT informed Northern Gulf that it would take full 100% control of the Exclusive Operation of the G6/48 Rossukon field development plan area. Northern Gulf remains a 40.0% working interest partner in the G6/48 reservation area, where KEGOT holds 30.0% and MP G6 holds 30.0%.

Exploration

Aside from the Montha-1 exploration well in G10/48, exploration activity was reduced to a minimum in 2018 and was centred on works committed under government agreement:

- In May 2018, the *Hai Yang Shi You 721* seismic vessel completed a 305 sq. km seismic acquisition program in the non-operated SS-11 exploration licence offshore Bangladesh in the Bay of Bengal; and
- The Ca Lang-1X exploration well commenced drilling on 23 May 2018 in the non-operated Block 120 PSC, offshore Vietnam. The well reached a total depth of 1,933 metres MD (-1,907 metres TDVSS) on 23 June 2018 without encountering hydrocarbons. The well was plugged and abandoned.

Concession updates

On 5 April 2018, the joint-venture partners signed the Andaman II PSC in the Malacca Strait offshore North Sumatra. The Andaman II PSC is an exploration block over the North Sumatra Basin covering an area of 7,400 sq. km in water depths ranging from 200 metres to 1,950 metres. The contract area was previously held under a joint study agreement. KrisEnergy holds 30.0% working interest in the Andaman II PSC and is partnered by the operator Premier Oil (40.0%) and Mubadala Petroleum (30.0%).

The Ministry of Industry and Trade in Vietnam approved a two-year extension of the KrisEnergy-operated Block 115/09 exploration PSC, offshore Vietnam.

The Indonesian authorities approved the final four-year exploration period for the KrisEnergy-operated Udan Emas PSC, onshore West Papua, Indonesia. The PSC was extended to 19 July 2022 and the gross acreage of the contract area was reduced to 1,070 sq. km.

Reserves and Contingent Resources

THE FOLLOWING RESERVES AND CONTINGENT RESOURCES TABLES HAVE BEEN EXTRACTED FROM THE QUALIFIED PERSON'S REPORT DATED 31 DECEMBER 2018 ("QPR"), AS PREPARED BY THE INDEPENDENT QUALIFIED PERSON, NSAI (TEXAS BOARD OF PROFESSIONAL ENGINEERS REGISTRATION NO. F-2699).

Mr. Scott Frost of NSAI is a Licensed Professional Engineer in the State of Texas (No. 88738) and a member of the Society of Petroleum Engineers and Mr. Allen Evans of NSAI is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1286) and a member of the American Association of Petroleum Geologists. Please also refer to the Appendix of this Annual Report for the executive summary of the QPR. The full QPR is available for inspection at our Singapore office during working hours by shareholders whose names appear in the CDP Registry or our Register of Members. Shareholders who wish to inspect the full QPR should write to KrisEnergy Ltd., 83 Clemenceau Avenue, #10-05 UE Square, Singapore 239920 to request an appointment.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterised by development and production status:

Proved reserves ("1P") are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If probabilistic methods are used, there should be at least a 90.0% probability that the quantities actually recovered will equal or exceed the estimate.

Probable reserves (together with 1P, "2P") are those additional reserves that are less likely to be recovered than 1P reserves but more certain to be recovered than possible reserves. When probabilistic methods are used, there should be at least a 50.0% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible reserves (together with 1P and 2P, "3P") are those additional reserves which analysis of geoscience and engineering data suggests are less likely to be recoverable than probable reserves. When probabilistic methods are used, there should be at least a 10.0% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

In the "low estimate" scenario of contingent resources ("1C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90.0%.

In the "best estimate" scenario of contingent resources (together with 1C, "2C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 50.0%.

In the "high estimate" scenario of contingent resources (together with 1C and 2C, "3C"), the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 10.0%.

Contingent resources are classified as development pending when there is a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan.

Contingent resources are classified as development unclarified when there is a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal and/or evaluation activities are required to clarify the potential for eventual commercial development.

Tables Notes

1 mmbbl refers to millions of barrels
2 bcf refers to billions of cubic feet
3 KrisEnergy ceased participation in the Block A Aceh PSC and Block G11/48 in late 2017 and first half 2018
4 The Tantawan field in B8/32 and the Rajpruek field in B9A permanently ceased operation on 31 October 2017. Abandonment activities are underway before the B9A licence is relinquished

Reserves

Date of report : 31 December 2018 | Date of previous report : 31 December 2017

	1P Reserves			2P Reserves			3P Reserves			
	Gross	Working Interest		Gross	Working Interest		Gross	Working Interest		Remarks
	(mmbbl[1])	(mmbbl)	Change from previous update (%)	(mmbbl)	(mmbbl)	Change from previous update (%)	(mmbbl)	(mmbbl)	Change from previous update (%)	
Oil										
Bangladesh										
Block 9	0.48	0.14	(20.9)	0.65	0.20	(19.9)	0.84	0.25	(18.8)	Lower production volumes and increased off-block recovery
Cambodia										
Block A	–	–	–	8.54	8.11	–	14.95	14.21	–	
Indonesia										
Block A Aceh PSC[3]	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
Thailand										
B8/32 & B9A[4]	10.93	0.51	46.4	60.70	2.81	(16.5)	77.27	3.58	(12.2)	1P reserves higher because of improved economic conditions. 2P and 3P reserves lower because of reduced long-term drilling plans and reduced remaining life to end of concession.
G6/48	–	–	–	11.70	5.03	43.3	15.80	6.79	43.3	Economic interest in production area increased from 30 to 43 per cent
G10/48	4.92	4.38	(42.3)	6.36	5.66	(53.2)	8.05	7.16	(50.2)	Lower well performance and reduced recovery for future wells
G11/48[3]	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
	(bcf[2])	(bcf)	Change from previous update (%)	(bcf)	(bcf)	Change from previous update (%)	(bcf)	(bcf)	Change from previous update (%)	
Gas										
Bangladesh										
Block 9	210.79	63.24	1.1	285.44	85.63	(11.7)	365.82	109.75	(11.0)	Lower production volumes and increased off-block recovery Decrease in 1P reserves offset by a well recompletion
Indonesia										
Block A Aceh PSC[3]	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
Bulu PSC	–	–	–	358.55	152.38	–	419.60	178.33	–	
Thailand										
B8/32 & B9A[4]	34.00	1.58	6.4	260.13	12.06	(40.6)	330.25	15.31	(39.5)	1P reserves higher because of improved economic conditions. 2P and 3P reserves lower because of reduced long-term drilling plans and reduced remaining life to end of concession.

Contingent Resources

	1C Resources			2C Resources			3C Resources			
	Gross	Working Interest		Gross	Working Interest		Gross	Working Interest		Remarks
	(mmbbl[1])	(mmbbl)	Change from previous update (%)	(mmbbl)	(mmbbl)	Change from previous update (%)	(mmbbl)	(mmbbl)	Change from previous update (%)	
Oil										
Bangladesh										
Block 9	0.02	0.01	–	0.11	0.03	–	0.54	0.16	–	
Cambodia										
Block A	0.91	0.86	–	1.74	1.65	–	3.13	2.97	–	
Indonesia										
Block A Aceh PSC[3]	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
Thailand										
G10/48	60.6	5.39	107.6	10.48	9.32	139.7	16.03	14.27	138.1	
G11/48	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
	(bcf[2])	(bcf)	Change from previous update (%)	(bcf)	(bcf)	Change from previous update (%)	(bcf)	(bcf)	Change from previous update (%)	
Gas										
Bangladesh										
Block 9	6.08	1.82	–	27.68	8.31	–	128.95	38.69	–	
Indonesia										
Bala-Balakang PSC	–	–	–	110.51	93.93	–	155.81	132.44	–	
Block A Aceh PSC[3]	–	–	(100)	–	–	(100)	–	–	(100)	Ceased participation
Sakti PSC	37.24	35.37	–	221.52	210.45	–	425.36	404.10	–	
Thailand										
G6/48	11.48	4.94	43.3	13.24	5.69	43.3	15.37	6.61	43.3	

Board of Directors

As at 1 April 2019

Tan Ek Kia (70)

Independent Non-Executive Chairman

Bachelor of Science Mechanical Engineering (First Class Honours), Nottingham University; Management Development Programme, International Institute for Management Development, Lausanne, Switzerland; Fellow of the Institute of Engineers, Malaysia; Chartered Engineer of Engineering Council U.K.; Member of Institute of Mechanical Engineers U.K.

Date of first appointment as director: 11 January 2013 **Length of service as a director:** 6 years 2 months **KrisEnergy board committee(s) served on:** Audit and Risk Management Committee (Member); Nominating Committee (Chairman); Executive Committee (Chairman) **Present directorships (as at 31 December 2018): Listed companies:** Keppel Corporation Ltd; KrisEnergy Ltd.; PT Chandra Asri Petrochemical Tbk; Transocean Ltd. **Other principal directorships:** SMRT Corporation Ltd; Dialog Systems (Asia) Pte Ltd; Keppel Offshore and Marine Ltd; Star Energy Group Holdings Pte Ltd (Chairman); Singapore LNG Corporation Pte Ltd. **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** City Gas Pte Ltd (Chairman), CitySpring Infrastructure Management Pte Ltd. **Others**: Former Vice President (Ventures and Developments) of Shell Chemicals, Asia Pacific and Middle East region (based in Singapore); Former Chairman, Shell companies in North East Asia (based in Beijing); Former Managing Director, Shell Malaysia Exploration and Production

Kelvin Tang (44)

Executive Director, Chief Executive Officer and President, Cambodia

Bachelor of Law, National University of Singapore; Advocate and Solicitor, Supreme Court of Singapore; Member of the Association of International Petroleum Negotiators

Date of first appointment as director: 9 November 2017 **Length of service as a director:** 1 year 4 months **KrisEnergy board committee(s) served on:** Executive Committee (Member) **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd. **Other principal directorships:** B Block Ltd; KrisEnergy (Aspara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Vietnam 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy Management Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pt Ltd; SJ Production Barge Ltd; KrisEnergy (Bangladesh) SS-11 Ltd; KrisEnergy G10 (Thailand) Ltd; KrisEnergy Management Ltd; KrisEnergy Asia Coöperatief U.A.; KrisEnergy Asia Holdings B.V.; KrisEnergy Netherlands Pte Ltd; KrisEnergy (Andaman II) Ltd; KrisEnergy (Apsara) Holding Ltd.; KrisEnergy (Apsara) Company Ltd. **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** Komodo (B.V.I.) Ltd; KrisEnergy (Ageng) B.V.; KrisEnergy (Andaman Timur) B.V.; KrisEnergy (Nemo) B.V.; KrisEnergy (Sakti) B.V.; KrisEnergy (Tanjung Aru) B.V.; KrisEnergy (Udan Emas) B.V.; KrisEnergy East Seruway B.V.; KrisEnergy Glagah-Kambuna B.V.; KrisEnergy (Andaman II) B.V.; KrisEnergy Kutai B.V.; KrisEnergy Kutei B.V.; KrisEnergy (Bangora) B.V. **Others**: Nil

Kiran Raj (46)

Alternate Executive Director (to Kelvin Tang), Chief Financial Officer and Vice President Finance and Administration

Bachelor of Commerce, Monash University; Chartered Accountant, Chartered Accountants Australia and New Zealand

Date of first appointment as director: 9 November 2017 **Length of service as a director:** 1 year 4 months **KrisEnergy board committee(s) served on:** Nil **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd. **Other principal directorships:** B Block Ltd; KrisEnergy (Aspara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Vietnam 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy Management Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Pt Ltd; KrisEnergy Marine Pte Ltd; SJ Production Barge Ltd; KrisEnergy (Bangladesh) SS-11 Ltd; KrisEnergy Asia Coöperatief U.A.; KrisEnergy Asia Holdings B.V.; KrisEnergy Netherlands Pte Ltd; KrisEnergy Glagah Kambuna B.V.; KrisEnergy (Marine) B.V.; KrisEnergy Kutai B.V.; KrisEnergy Kutei B.V.; KrisEnergy (Andaman II) B.V.; KrisEnergy East Seruway B.V.; KrisEnergy (Bala-Balakang) B.V.; KrisEnergy (Andaman Timur) B.V.; KrisEnergy (Ampuh) B.V.; KrisEnergy (Nemo) B.V.; KrisEnergy (Sakti) B.V.; KrisEnergy (Udan Emas) B.V.; KrisEnergy Bangladesh Ltd; KrisEnergy (Block A Aceh) B.V.; KrisEnergy (Andaman II) Ltd; KrisEnergy (Apsara) Holding Ltd.; KrisEnergy (Apsara) Company Ltd; Grill'd Group Singapore Pte Ltd. **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** KrisEnergy Management Ltd; KrisEnergy G10 (Thailand) Ltd. **Others**: Former Director of CLSA Merchant Bankers Limited; Former Director and Head of Investment Banking Execution CLSA Merchant Bankers Ltd: and Former Director and Chief Executive Officer of Brighton Capital Advisors Pte. Ltd.

Chris Ong Leng Yeow (45)

Non-Executive Director

Bachelor Degree in Electrical and Electronics Engineering and Master degree in Electrical and Electronics Engineering, National University of Singapore; Chartered Engineer; Fellow of the Institute of Marine Engineering, Science and Technology; Member of the American Bureau of Shipping; Member of the DNV GL South East Asia and Pacific Committee; Member of Bureau Veritas Marine; Committee Member of Offshore Asia-Australia

Date of first appointment as director: 5 January 2018 **Length of service as a director:** 1 years 2 months **KrisEnergy board committee(s) served on:** Nominating Committee (Member); Remuneration Committee (Member) **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd. **Other principal directorships:** FELS Offshore Pte Ltd; Keppel Amfels LLC; Keppel FELS Limited; Keppel LeTourneau Middle East FZE; Keppel Nantong Heavy Industry Co Ltd; Keppel Nantong Shipyard Co Ltd; Keppel Shipyard Limited; Northstar Investments Pte. Ltd; Keppel Singmarine Pte Ltd; Caspian Shipyard Company LLC; Blue Tern Ltd. (formerly known as Seafox 5 Limited); Antares Singapore Pte Ltd; Asian Lift Pte Ltd; Keppel Offshore & Marine Ltd; Gas Technology Development Pte Ltd; Keppel FELS Brasil S.A.; FueLNG Pte Ltd; Ocean Mineral Singapore Pte Ltd; Ocean Mineral Singapore Holding Pte Ltd; Keppel Technology and Innovation Pte Ltd; Keppel Walvis Bay Offshore and Marine (Pty) Ltd. **Major appointments (other than directorships):** Chief Executive Officer of Keppel Offshore & Marine Ltd; Managing Director of Keppel FELS Limited **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** City Gas Pte Ltd (Chairman), CitySpring Infrastructure Management Pte Ltd. **Others**: Former Assistant Section Manager, Section Manager, Deputy Engineering Manager, Assistant General Manager (Engineering), General Manager (Engineering), Acting Executive Director (Operations), Executive Director (Commercial) and Deputy Managing Director of Keppel FELS Limited

John Koh (63)

Non-Executive Independent Director

Bachelor of Arts and Master of Arts, University of Cambridge; Master of Law, Harvard Law School

Date of first appointment as director: 11 January 2013 **Length of service as a director:** 6 years 2 months **KrisEnergy board committee(s) served on:** Audit and Risk Management Committee (Chairman); Nominating Committee (Member); Executive Committee (Member) **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd.; NSL Ltd; Mapletree Industrial Trust **Other principal directorships:** BMH Management Pte Ltd; Brandmine Properties Ltd; Mapletree Industrial Trust Management Ltd (as Trustee Manager of Mapletree Industrial Trust); National Library Board; Aurora Mobile Ltd. **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** Arbutus International Ltd; China Lumena New Materials Corp; Mission Impossible International Ltd; School of the Arts; Mapletree Industrial Fund Ltd; Worldwide Books Corporation **Others**: Former Managing Director and Senior Advisor of the Goldman Sachs Group; Former Deputy Public Prosecutor in the Singapore Attorney-General's Chambers; Former Deputy Director of the Commercial Affairs Department in the Ministry of Finance

Duane Radtke (70)

Non-Executive Independent Director

Bachelor Degree in Mining Engineering, University of Wisconsin

Date of first appointment as director: 1 September 2010 **Length of service as a director:** 8 years 6 months **KrisEnergy board committee(s) served on:** Nominating Committee (Member); Remuneration Committee (Chairman) **Present directorships (as at 31 December 2018): Listed companies:** Devon Energy Corporation; KrisEnergy Ltd. **Major appointments (other than directorships):** President and Chief Executive Officer of Valiant Exploration LLC **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** Sabine Oil & Gas Corporation **Others**: Former President of Devon International Corporation; Former President and Chief Executive Officer of Dominion Exploration and Production

Alan Nisbet (68)

Non-Executive Independent Director

Member of the Institute of Certified Public Accountants of Singapore (ICPAS)

Date of first appointment as director: 13 May 2014 **Length of service as a director:** 4 years 2 months **KrisEnergy board committee(s) served on:** Audit and Risk Management Committee (Member); Remuneration Committee (Member) **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd.; Halcyon Agri Corporation Ltd; Keppel REIT Management Limited **Other principal directorships:** Standard Chartered Bank (Singapore) Ltd; Ascendas Property Fund Trustee Pte Ltd; RF Brussels Pte. Limited; RF Capital (Advisory) Pte. Limited; RF Capital (Credit) Pte. Limited; RF Capital (Empirica) Pte. Limited; RF Capital (Services) Pte. Limited; RF Capital Pte. Limited; RF ECP Pte. Limited; RF Holdings Pte. Limited; Roberts Constructions Pte. Limited; Roberts Investments Holdings Pte. Limited; Robert Investments Pte. Limited; RF Corval REFM Pte. Ltd; RF Corval Capital Partners Pte. Limited; PF Corval Pte. Limited; RF Renewables Pte. Limited; RF Corval Europe Pte. Limited; RF Corval Holdings Pte. Limited; RF Corval Logistics Pte. Limited; RF Corval MEA Pte. Limited **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** Ascendas Pte Ltd; RF Capital (Private Equity) Pte. Limited; RF Capital (Real Estate) Pte. Limited; Deloitte & Touche Management Services Pte Ltd; Deloitte Consulting SEA Pte Ltd. **Others**: Former Partner and Audit Leader in Deloitte & Touche LLP, Singapore

Keith Pringle (60)

Non-Executive Independent Director

Bachelor of Science (Hons) in Geology, Edinburgh University; Master of Science in Petroleum Engineering, Strathclyde University

Date of first appointment as director: 13 May 2014 (original appointment: 5 October 2009 – 31 August 2010) **Length of service as a director:** 4 years 10 months (9 years 5 months from original appointment) **KrisEnergy board committee(s) served on:** Audit and Risk Management Committee (Member); Remuneration Committee (Member) **Present directorships (as at 31 December 2018): Listed companies:** KrisEnergy Ltd. **Other principal directorships:** Nil **Major appointments (other than directorships):** Nil **Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018):** Remora Energy; Delta Energy Ltd; KrisEnergy Ltd. **Others**: Founding Director and Former Independent Technical Advisor to KrisEnergy Ltd.

Management Team

As at 1 April 2019

James Parkin (60)
Chief Operating Officer

Mr. Parkin has been with KrisEnergy since inception and has more than 37 years of experience in the upstream oil and gas sector, of which he has spent over 30 years in Southeast Asia. Mr. Parkin oversees efficiency of the Group's producing assets as well as the multiple workstreams associated with KrisEnergy-operated development projects. Prior to KrisEnergy, Mr. Parkin was Vice President Exploration from 2003 until 2009 and acting Regional Vice President, Southeast Asia from 2008 until 2009 for Pearl Energy.

He began his career in 1979 as a Mudlogger and was later a Wellsite Geologist with Exploration Logging International. From 1986 until 1990, he worked at British Gas as an Operations Geologist. In 1990, Mr. Parkin moved to Indonesia and worked as a Senior Geologist for Petromer Trend until 1993 and later became a Senior Exploration Geologist for Union Texas Petroleum until 1997 and Far East Exploration Co. Ltd. until 1998. From 1998 until 2003, Mr. Parkin was a Senior Geologist and then Team Leader East Java at Gulf Indonesia/Conoco/Conoco Phillips.

Mr. Parkin holds a Bachelor of Science (Hons) in Geology from the University of Sheffield and a Master of Science in Petroleum Geology from the Imperial College of Science and Technology, University of London. Mr. Parkin is a member of the South East Asia Petroleum Exploration Society, Indonesian Petroleum Association, Petroleum Exploration Society of Great Britain and Geological Society, UK.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Sally Ting (42)
General Counsel

Ms. Ting joined KrisEnergy in 2015 and is responsible for the legal and regulatory functions of the company. She has more than 20 years of legal and oil and gas experience in the Asia-Pacific region.

Ms. Ting started her career at Australian legal firm Mallesons Stephen Jaques (now King & Wood Mallesons) in 1999 and stayed until 2002. Ms. Ting moved to Singapore in 2002 and joined Coudert Brothers LLP from 2002 until 2005 in their corporate practice. From 2005 until 2007, she was an associate with Milbank Tweed Hadley McCloy in Singapore where she advised on a number of corporate transactions in the oil and gas sector across Southeast Asia. In 2007, Ms. Ting joined Salamander Energy (now Ophir Energy) as Regional Counsel where she was responsible for the legal and regulatory function of the company in the Southeast Asia region.

Ms. Ting holds a Bachelor of Science degree and a Bachelor of Law degree (First Class Honours and University Medal) from the University of Queensland. She is also a member of the Association of International Petroleum Negotiators.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Brian Helyer (61)
Vice President Operations

Mr. Helyer joined KrisEnergy in 2010 and has worked in the offshore oil and gas industry for 40 years. Mr. Helyer looks after all aspects of project management for facilities construction, operations, maintenance and commissioning for KrisEnergy and is also responsible for the writing and implementation of Environmental Health Safety and Security policy across the Group. Notably, he oversaw progress of the facilities construction and installation at the Wassana oil field, KrisEnergy's first greenfield development to go into production in the Gulf of Thailand. This included the procurement and refurbishment of the *MOPU Ingenium*. First oil for Wassana was produced 15 months after KrisEnergy took over operatorship of the licence in May 2014.

Prior to KrisEnergy, Mr. Helyer was the Project and Operations Director for Songa Floating Production, and was responsible for the conversion and class approval of the floating production, storage and offloading vessel, *FPSO East Fortune*. Between 2003 and 2007, he worked for Petrofac Energy Developments in various roles such as Production Manager, Business Development Manager and Project Manager in Indonesia, Malaysia, United Kingdom and Tunisia. From 1999 to 2005, Mr. Helyer was Field Operations Manager at the Kakap oil field in the South China Sea for Gulf Resources (Indonesia). He also spent 15 years with Marathon Oil in various roles in the United Kingdom and Indonesia. Mr. Helyer has attained the National Examination Board in Occupational Safety and Health ("NEBOSH") professional safety accreditation and is a member of the International Institute of Risk Management (IIRM) and the Institute of Occupational Safety and Health (IOSH).

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Tim Kelly (59)

Vice President Engineering

Mr. Kelly has more than 37 years of experience in the upstream oil industry with the last 30 years spent in Southeast Asia, during which time he has been involved in the appraisal and development of new fields and the reservoir and production management of mature fields.

Mr. Kelly was Corporate Petroleum Engineering Manager for Pearl Energy between 2003 and 2009 in Singapore and was involved in projects in Indonesia, Philippines, Thailand and Vietnam. Between 1989 and 2003, Mr. Kelly was based in Jakarta as Engineering Manager for Marathon Oil, Clyde Petroleum and Gulf Indonesia, and as DST Specialist with ExxonMobil. He began his career in 1981 with Phillips Petroleum as a Drilling & Reservoir Engineer working in the United States and Singapore.

Mr. Kelly holds a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines. He is a member of the Society of Petroleum Engineers and the South East Asia Petroleum Exploration Society.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Michael Whibley (60)

Vice President Technical

Mr. Whibley joined KrisEnergy in 2009 and is a geologist with over 39 years of management, operational and interpretive experience in exploration and development projects and new business development. He has been based in Asia for the last 26 years.

Prior to joining KrisEnergy, Mr. Whibley held senior management and senior technical roles in Singapore with Pearl Energy-Aabar-Mubadala in Singapore between 2006 and 2009, and in Jakarta, Indonesia, with Amerada Hess from 2003 until 2006, and Santa Fe Energy-Devon Energy-PetroChina between 1998 and 2003, Santos Ltd. from 1997 until 1998, and Apache Corporation from 1993 until 1997. Mr. Whibley worked in Perth, Australia originally with Phillips Petroleum as a graduate geologist from 1980 until 1983 and later with Bond Energy Resources-Occidental Petroleum-Hadson Energy between 1983 and 1993 as a Senior Explorationist. Mr. Whibley's experience is predominately throughout Asia (Indonesia, Thailand, Indochina and South Asia) and Australasia (Papua New Guinea, Timor Sea, and North West Shelf).

Mr. Whibley graduated from the University of Western Australia with a Bachelor of Science (Hons) in Geology and is a member of the Indonesian Petroleum Association, South East Asian Exploration Society and the American Association of Petroleum Geologists. He is also the Chairman and Committee member of the Asia Pacific Scoutcheck (APSC).

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Chris Wilson (47)

Vice President Commercial

Mr. Wilson joined KrisEnergy in 2009 and is a strategist responsible for the origination and execution of corporate and asset acquisitions/divestitures for the Group and in particular, the valuation of new business opportunities. He is also responsible for the Group's crude oil portfolio sales and marketing activities.

Between 2003 and 2009, he was the in-house Financial Advisor for Pearl Energy, working on all aspects of fundraising and acquisition opportunity evaluation, including reserves-based lending facilities, pre-IPO private equity placements, the company's initial public listing in 2005 and all key asset acquisitions.

In 2002, Mr. Wilson was a consultant with the Asian Development Bank. From 1997 until 2001, he was Assistant Vice President in the Project Finance Group of ABN AMRO in Singapore focusing initially on project advisory transactions in the power sector and later moving into lending and advisory in the oil and gas sector. Mr. Wilson began his career in 1995 with Chase Manhattan Bank as a private equity analyst for Chase Capital Partners in Hong Kong before moving to Singapore to take up the role of Assistant Vice President in the Risk Asset Management Group.

Mr. Wilson holds a Bachelor of Arts in International Relations from the John Hopkins University, Baltimore in Maryland and a Master of Arts in China Studies from the Paul H. Nitze School of Advanced International Studies in Washington D.C. in the United States. He is a member of the Association of International Petroleum Negotiators and the South East Asia Petroleum Exploration Society.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Panotech Pte Ltd.

Edwin Bowles (65)

General Manager, Bangladesh

Mr. Bowles joined KrisEnergy in 2014 and is a geologist with more than 37 years of experience in Malaysia, India, Pakistan, UK, Middle East, North Africa and Sub-Saharan Africa. The majority of his career has been spent with British Gas and its overseas subsidiaries.

Key roles which he has held prior to KrisEnergy include Exploration Manager West Africa, General Manager Pakistan and Managing Director of Gujarat Gas Company, India. In 2008, Edwin established RJ Energy, which acts as a strategic advisor to ministries, state oil companies and international oil companies. This followed an extensive assignment with the UK government as an advisor on oil and gas matters where he held key appointments in several energy advisory groups including those for Libya, Morocco, Egypt and Nigeria.

Mr. Bowles holds a Bachelor of Science (Hons) in Geology from Southampton University and a Master of Science, Geology from Imperial College of Science and Technology, University of London. He is a member of the Petroleum Exploration Society of Great Britain, American Association of Petroleum Geologists and the Geological Association.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): RJ Energy Ltd; SAER Ltd.

Management Team

As at 1 April 2019

Malin Ros (53)
General Manager, Cambodia

Ms. Ros was appointed General Manager of KrisEnergy's Cambodian operations in October 2014 following the company's acquisition of Chevron Cambodia. Ms. Ros has more than 27 years of experience in the upstream oil and gas industry. She started her career in 1992 as an Administrator in the Cambodian office of Enterprise Oil Exploration, a British exploration and production company.

Ms. Ros took over the role of Office Manager in 1997 and was Enterprise Oil's local representative in Cambodia from 1999 onwards. After Royal Dutch Shell's acquisition of Enterprise Oil in 2002, Ms. Ros joined Chevron Overseas Petroleum (Cambodia) as Country Manager and was responsible for local government relations, operations and community engagement.

Ms. Ros holds a Bachelor of Arts in Economics and a Master of Business Administration from the National University of Management in Phnom Penh, Cambodia.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Basuki Kusmutarto (57)
General Manager, Indonesia

Mr. Basuki joined KrisEnergy in July 2010, bringing extensive local knowledge and experience in the upstream sector. He began his career in 1987 as a Consulting Engineer at PT SUCOFINDO, a state-owned inspection, testing and certification company, and later became Vice President of the Mineral Service Division.

In 2003, he joined Pearl Energy as General Manager for its Indonesia operations until 2010.

Mr. Basuki holds a Bachelor of Science in Chemical Engineering from the Bandung Institute of Technology and has an MBA from the Institute Pengembangan Manajemen Indonesia. Mr. Basuki is a member of the Indonesian Petroleum Association.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Phattarin Jirapojaporn (43)
General Manager, Thailand

Ms. Jirapojaporn joined KrisEnergy in 2010. She holds an Executive Master of Business Administration from the Sasin Graduate Institute of Business Administration of Chulalongkorn University and started her career in 2001 as a business analyst with Thai Shell Exploration and Production. She later went on to work on contract analysis in procurement and contract management.

Between 2007 and 2009, she was a business analyst for Hess Corporation with a primary focus on oil and gas assets in Thailand. Prior to joining KrisEnergy, she was a senior manager of group financial planning and analysis at Thoresen Thai Agencies Plc, a strategic investment holding company with three primary business groups – Transport, Energy, and Infrastructure.

Ms. Jirapojaporn also holds a Bachelor of Business Administration, Finance & Banking and a Master of Science in Computer Information Systems from Assumption University.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Nguyen Truong Giang (51)
General Manager and Exploration Manager, Vietnam

Mr. Nguyen joined KrisEnergy in 2011. He has more than 21 years of experience in oil and gas exploration in Vietnam. He has been involved in a variety of projects from exploration and development to new business across key oil-and-gas producing basins in Vietnam.

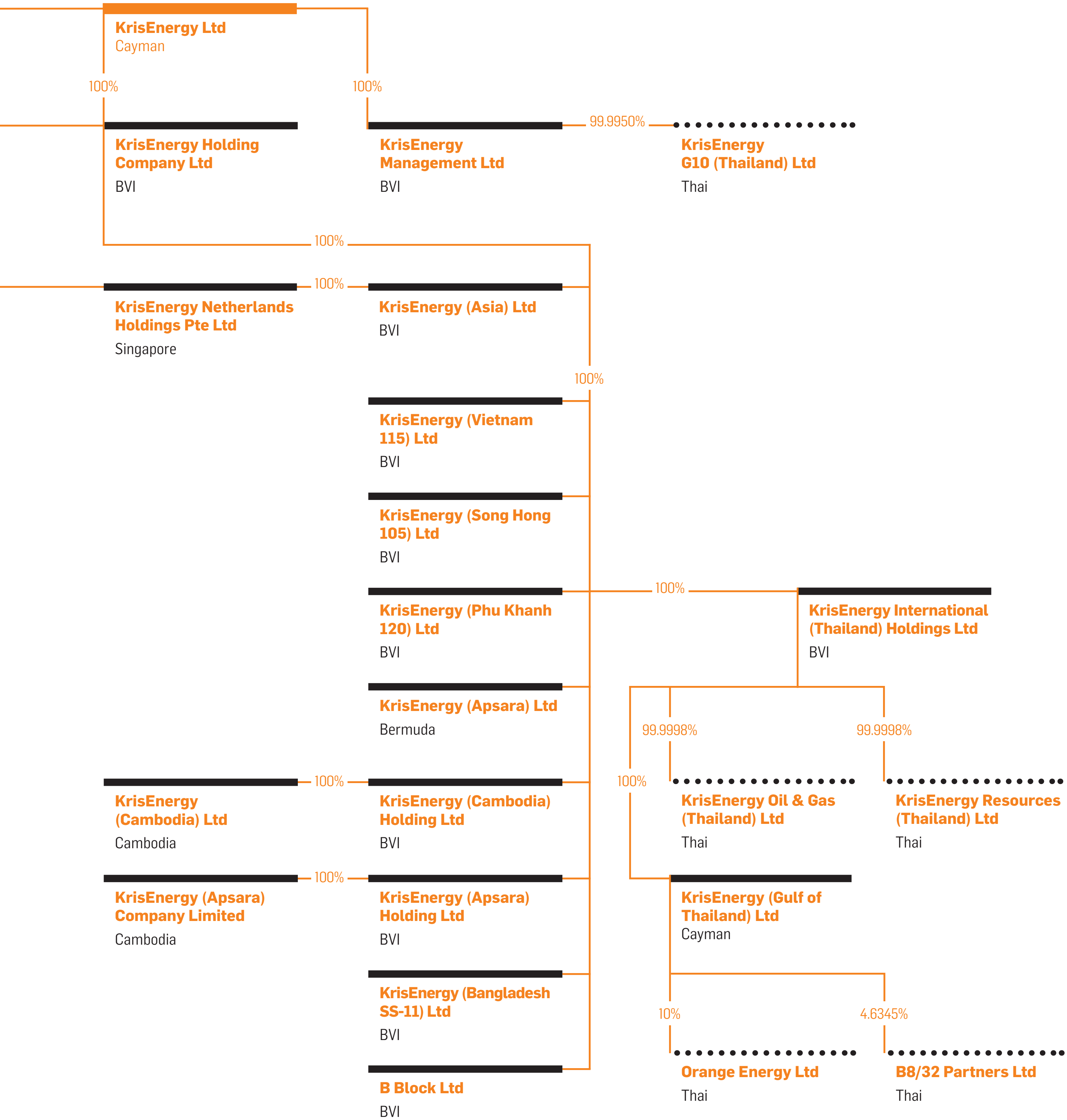
Mr. Nguyen was Chief Geophysicist for Pearl Energy between 2008 and 2010. Between 2002 and 2008, Mr. Nguyen was a senior exploration geophysicist under a joint venture with ConocoPhillips Vietnam. He began his career in 1997 as a seismic processor based in Ho Chi Minh City under a joint venture with Petrovietnam and Fairfield Industries Inc. USA.

Mr. Nguyen has a Bachelor of Science in Geophysics from Hanoi University of Geology and Mining and a Master of Science in Applied Petroleum Geology from HCMC University of Technology. Mr. Nguyen is a member of the Society of Exploration Geophysicists and the South East Asian Exploration Society.

Past principal directorships held over the preceding 5 years (from 1 January 2014 to 31 December 2018): Nil

Group Structure

As at 1 April 2019



KrisEnergy Ltd
Cayman
100%
100%
KrisEnergy Holding Company Ltd
BVI
KrisEnergy Management Ltd
BVI
99.9950%
KrisEnergy G10 (Thailand) Ltd
Thai
100%
100%
KrisEnergy Netherlands Holdings Pte Ltd
Singapore
KrisEnergy (Asia) Ltd
BVI
100%
KrisEnergy (Vietnam 115) Ltd
BVI
KrisEnergy (Song Hong 105) Ltd
BVI
KrisEnergy (Phu Khanh 120) Ltd
BVI
100%
KrisEnergy International (Thailand) Holdings Ltd
BVI
KrisEnergy (Apsara) Ltd
Bermuda
99.9998%
99.9998%
100%
KrisEnergy Oil & Gas (Thailand) Ltd
Thai
KrisEnergy Resources (Thailand) Ltd
Thai
100%
KrisEnergy (Cambodia) Ltd
Cambodia
KrisEnergy (Cambodia) Holding Ltd
BVI
100%
KrisEnergy (Apsara) Company Limited
Cambodia
KrisEnergy (Apsara) Holding Ltd
BVI
KrisEnergy (Gulf of Thailand) Ltd
Cayman
KrisEnergy (Bangladesh SS-11) Ltd
BVI
10%
4.6345%
Orange Energy Ltd
Thai
B8/32 Partners Ltd
Thai
B Block Ltd
BVI

Corporate Governance

THE BOARD OF DIRECTORS (THE "BOARD") AND MANAGEMENT OF KRISENERGY ARE COMMITTED TO HIGH STANDARDS OF CORPORATE GOVERNANCE, BUSINESS INTEGRITY AND PROFESSIONALISM. TO THIS END, KRISENERGY CONFIRMS THAT IT HAS COMPLIED IN ALL MATERIAL ASPECTS WITH THE PRINCIPLES AND GUIDELINES OF THE CODE OF CORPORATE GOVERNANCE 2012 (THE "2012 CODE").

ANY DEVIATIONS ARE APPROPRIATELY EXPLAINED WITHIN THIS CORPORATE GOVERNANCE REPORT AND THE BOARD HAS CONSIDERED THAT THE ALTERNATIVE PRACTICES ADOPTED ARE SUFFICIENT TO MEET THE UNDERLYING INTENT OF THE 2012 CODE.

ALTHOUGH THE CODE OF CORPORATE GOVERNANCE 2018 WILL ONLY APPLY FOR THE FINANCIAL YEAR COMMENCING 1 JANUARY 2019, WE HAVE WHERE POSSIBLE ADHERED TO THE PRINCIPLES AND PROVISIONS PROVIDED.

WITH SPECIFIC REFERENCE TO THE 2012 CODE, OUR CORPORATE GOVERNANCE PRACTICES ARE SET OUT ON THE FOLLOWING PAGES.

Principle 1

Board Responsibility

Accountable for the Group's activities, strategy, governance, risk management and financial performance, the Board ensures that the corporate responsibility and ethical standards of the Group are met by overseeing the conduct of its affairs and exercising its fiduciary role in the interests of the Group, with the objective to create value for stakeholders and ensure the sustainable success of the Company. Specifically, its principal functions include:

- setting strategic direction and long-term targets and ensuring that resources are set aside to meet the targets;
- overseeing the business and affairs of the Group and instituting, with management, the strategies and financial objectives to be enforced by management, and monitoring the performance of management;
- approving the appointment of the Chief Executive Officer, Directors and the succession planning process;
- overseeing a framework for evaluating adequacy of internal controls, risk management systems, financial reporting and compliance to safe guard stakeholders' interests;
- setting the values and standards (including ethical standards) of the Company;
- assuming responsibility for corporate governance; and
- considering sustainability issues of policies and proposals.

Independent Judgement

The Directors are expected to exercise due diligence and independent judgement in the best interests of the Company.

Delegation by the Board

Although the Board retains overall responsibility, to assist the Board with oversight of various specific responsibilities, the Audit and Risk Management, Nominating, Remuneration and Executive Committees are delegated the necessary authority by the Board. Established with clear written terms of reference, in compliance with the 2012 Code, each Committee operates with a specific set of duties, authority and accountability. Individually, each Committee plays a pivotal role in ensuring good corporate governance practices within the Group.

Meeting and Attendance

Meeting every quarter and ad hoc as warranted by circumstances, the schedules for all Board and Committee meetings for the next calendar year are planned in advance, in consultation with the Directors. Non-executive Directors also meet each quarter without the presence of management upon conclusion of the Board and Committee meetings. The Company's Articles of Association ("Articles") permit telephonic attendance and conference for Board and Committee meetings. The Board and Committees may also make decisions by way of circulating written resolutions.

Aside from reviewing the Group's financial performance, annual work program and budget, corporate strategy, business plans, potential acquisitions and divestments and significant operational matters, the Chairman of each Committee provides updates from their respective Committee meetings to the Directors. Additionally, management provides the Board with regular email and teleconference updates regarding operations, financial performance and where applicable, developments in, and the Group's compliance with, corporate governance requirements and other regulations.

Table 1 sets out the number of meetings held by the Board and the Audit and Risk Management, Nominating and Remuneration Committees since 1 January 2018 to the end of the financial year under review, as well as the attendance of each Board member.

Management endeavours to provide timely dissemination of all papers and materials for discussion regardless of a Director's ability to physically attend a Board Meeting. Upon reviewing such materials, Directors are expected to advise the Chairman or Committee Chairman of views and comments on the matters at hand in order that they may be conveyed to other Board members and discussed at the meeting.

Table 1: Directors' attendance at board and committee meetings during the financial year under review

	Board Meetings[1]	Committee Meetings[1]		
Name of Director		**Audit and Risk Management**	**Nominating**	**Remuneration**
John Koh	3	4	4	3[2]
Duane Radtke	3	4[2]	4	4
Tan Ek Kia	3	4	4	4[2]
Alan Nisbet	3	3	3[2]	3
Keith Pringle	3	4	4[2]	4
Chris Ong Leng Yeow	3	4[2,3]	4	3[2,3]
Kelvin Tang	3	4[2]	3[2]	4[2]
Kiran Raj (Alternate Director to Kelvin Tang)	3	4[2]	–	2[2]
Chan Hon Chew[4]	3	4[2,5]	1[2]	2[2,5]
Michael Chia[6]	–	–	–	–
Total No. of Meetings Held	**3**	**4**	**4**	**4**

NOTES:

1 Refers to meetings held/attended while each Director was in office. This excludes board update and discussion sessions.

2 By invitation

3 Re-designated from Audit and Risk Management Committee to Remuneration Committee with effect from 22 May 2018

4 Resigned from the Board on 31 December 2018

5 Re-designated from Remuneration Committee to Audit and Risk Management Committee with effect from 22 May 2018

6 Resigned from the Board (and replaced with Chris Ong Leng Yeow) on 5 January 2018

Board Approval

Appropriate internal guidelines have been put in place which set forth matters requiring Board approval. The Board approves matters relating to, amongst others, (i) acquisitions and disposals of material assets; (ii) plans of development for petroleum assets; (iii) the Group work program and budget; and (iv) all material commitments to corporate and project financing from banks and financial institutions. This allows management to focus on its responsibilities for the day-to-day operation and administration of the Company.

Further, the Company implements a management approval authority policy which sets out authority levels to which management is expected to adhere in respect of entering into commitments, approving expenditure, authorising payments and agreeing and settling liabilities on behalf of the Group. The policy thus ensures that decisions are taken at an appropriate level consistent with (i) maintaining the implementation of any policy decided upon by the Board; and (ii) maintaining appropriate internal controls to safeguard the assets and resources of the Group, while at the same time seeking efficiency of operation and devolving responsibility.

Board Induction

All newly appointed Directors are provided induction letters detailing their duties and responsibilities. Management also conducts an orientation program, which serves as a comprehensive and tailored induction, outlining the Company's business, strategic plans, objectives and governance practices, amongst others.

Board Training

Directors are informed of, and arrangements are made for them to attend, any appropriate and relevant courses which promote their professional development and encourage the highest standards of corporate governance and ethical conduct. Annual training sessions on topics such as Directors' duties and responsibilities, corporate governance, changes in financial reporting standards, insider trading and changes in industry-related matters are conducted by an external expert. In particular, Directors have attended an update session during the year conducted by external legal counsels on recent amendments to the Code of Corporate Governance.

Principle 2

Board Composition and Guidance

Board Size, Composition and Competency

In parallel with the developing objectives of the Company and the industry, the Board, together with the Nominating Committee, evaluates on a regular basis the size of the Board, its composition and the mix of competencies of Board members. The Nominating Committee places great importance on the necessity for Directors to possess a wide array of expertise, skills and attributes, including relevant core competencies in areas such as accounting and finance, business and management, the oil and gas industry, strategic planning and knowledge of risk management. These factors are taken into account when the Nominating Committee recommends Director appointments. The Board, with the concurrence of the Nominating Committee, agrees that the current composition of the Board (taking into consideration the recent changes to the Board) provides an appropriate balance and diversity of skills, experience and knowledge of the Company and its business without interfering with efficient and effective decision-making. Non-executive Directors make up a majority of the Board.

Board Independence

In determining the independence of Directors, the Nominating Committee conducts an annual review, taking into account the 2012 Code definition of an Independent Director and the guidance the 2012 Code and the Listing Manual of the SGX-ST provide as to the type of relationships which would preclude a Director from being independent. The Nominating Committee will specifically take into consideration a Director's relationships with the Company, its substantial shareholders, its officers, or its related corporations, and whether such relationships could interfere, or be reasonably perceived to interfere, with the exercise of the Director's independent business judgement in the best interests of the Company. In addition, each of the Independent Directors provides an independence declaration annually. Save for Keith Pringle, none of the Directors have served more than nine years with the Company.

The Board, taking into account the views of the Nominating Committee, considers the following Directors independent: John Koh, Duane Radtke, Tan Ek Kia, Alan Nisbet and Keith Pringle.

The Board is helmed by an Independent Chairman and the Independent Directors comprise a majority of the Board.

Board Information

A crucial feature of a robust and effective Board is an open and constructive environment for Board members to contest and query management on its proposals and assumptions. Regular teleconference meetings are held to update the Board on the Company's operations and to provide Directors a platform to provide views and judgements. Further, as and when necessary, management holds informal meetings to brief Directors on prospective transactions and potential developments at an early stage prior to seeking formal Board approval. These informal briefings are usually accompanied with detailed Board memorandums.

Due to the prolonged volatile state of oil and gas prices which impacted the Company's financial health and necessitates a more active role by the Board in the Company's financial matters and state of affairs, management holds regular teleconferences where possible to ensure that the Board is provided with the most updated information.

Meeting of Directors without management: Non-executive Directors and Independent Directors hold meetings after Board meetings as appropriate to discuss matters without the presence of management. The Chairman of such meetings provides feedback to the Board and/or Chairman as appropriate.

Other Committees

In addition to the Audit and Risk Management, Nominating and Remuneration Committees, the Company has an Executive Committee (constituted in April 2017), which meets when required to assist the Board in executing its duties. (The former Technical Committee and Transition Committee have been dissolved in April 2017).

Each Committee may make decisions on matters within its terms of reference and applicable limits of authority. The terms of reference of each Committee are reviewed from time to time, as are the structures and memberships of the Committees.

Executive Committee

The Executive Committee is chaired by Tan Ek Kia and also comprises John Koh and Kelvin Tang. The Executive Committee comprises two Independent Non-executive Directors. The terms of reference for the Executive Committee include:

- providing advisory support, guidance and oversight to the Chief Executive Officer and management in the conduct of the Company's business (including but not limited to the review of capital expenditures, opera tional expenditures and management approval authority policy), as and when required;
- undertaking decisions required by the Company which exceed the financial limit authority of the Chief Executive Officer, provided that such decisions are not specifically reserved for the Board or other supervisory persons / Committees; and
- undertaking generally other functions, duties and powers as may be required by the Board or the Committee from time to time.

Principle 3

Chief Executive Officer & Chairman

Chief Executive Officer

Kelvin Tang, who is concurrently an Executive Director of the Company, was appointed Chief Executive Officer with effect from 1 September 2017, in substitution of the then Interim Chief Executive Officer, Jeffrey S. MacDonald.

Separation of the Role of Chairman and Chief Executive Officer

A separation of roles and powers between the Chairman and the Chief Executive Officer ensures an appropriate balance of power, greater accountability and increased capacity of the Board for independent decision making. The division of responsibilities between them are clearly established and agreed by the Board and no one individual has unfettered powers of decision-making.

Tan Ek Kia, an Independent Non-executive Director, was appointed Independent Non-executive Chairman with effect from 23 February 2017. The current Chairman is not related to the Chief Executive Officer.

Spearheading a high standard of corporate governance, the Independent Non-executive Chairman, who also chairs the Nominating Committee and the Executive Committee, guides the Board with the aid of Directors, Company Secretaries and management to ensure its effectiveness in all aspects of its role. The Independent Non-executive Chairman sets the agenda and monitors the flow of information from management to the Board to ensure all material information is provided in a timely manner for Directors to review and discuss. The Independent Non-executive Chairman encourages and promotes communication and constructive relations between the Board and management, and between Executive and Non-executive Directors, and is available to shareholders and all stakeholders should they have any concerns which have failed to be resolved by contact through the Chief Executive Officer or the Chief Financial Officer. The Chief Executive Officer manages and oversees the Group's business. Other Executive Directors and management provide assistance to the Chief Executive Officer in making strategic proposals to the Board. Pursuant to open and constructive Board discussion, the Chief Executive Officer formulates plans to execute the agreed strategy and implements Board decisions.

Principle 4

Board Membership

Nominating Committee

The Nominating Committee is chaired by Tan Ek Kia and also comprises John Koh, Chris Ong Leng Yeow and Duane Radtke. The Nominating Committee comprises entirely Non-executive Directors, of which three out of four (including the Nominating Committee Chairman) are independent.

The key terms of reference for the Nominating Committee include:

- reviewing and recommending candidates for appointments to the Board and Board Committees (excluding the appointment of existing members of the Board to each of the Audit and Risk Management Committee, the Nominating Committee and the Remuneration Committee for the purposes of the initial establishment of such Board committees), as well as candidates for senior management staff, who are not also candidates for appointment to the Board;
- developing of a process for evaluation of the performance of the Board, the Board Committees and the Directors;
- reviewing and recommending nomination for re-appointment or re-election or renewal of appointment of the Directors;

- reviewing of Board succession plans for the Directors, in particular, the Chairman and the Chief Executive Officer;
- reviewing of training and professional development programs for the Board;
- determining independence of the Directors; and
- undertaking generally such other functions and duties as may be required by law or the Listing Manual of the SGX-ST, and by amendments made there to from time to time.

Recommendation of Directors

The Board has a formal and transparent process for the appointment and re-appointment of Directors. The Nominating Committee initiates the review and recommendation of all nominations and re-nominations of Directors and Committee members, taking into account the composition and progressive renewal of the Board and each Director's competencies, commitment, contribution and performance. The Company's Articles require Directors to retire at least once every three years. The Company has, for this purpose, adopted a policy of retiring one-third of Directors from office by rotation at each Annual General Meeting ("AGM") and these Directors will be eligible for re-election at that AGM. The Articles also stipulate that Directors appointed by the Board during a financial year, shall only hold office until the next AGM, and thereafter be eligible for re-election at the AGM.

Review of Directors' Independence

Principle 2 "Board Composition and Guidance" of this corporate governance report sets out the guidelines for the Nominating Committee's determination of a Director's independence on an annual basis.

Directors' Time Commitments

Factors such as multiple board representations are taken into consideration by the Nominating Committee when deciding whether a Director is able to devote sufficient time and attention to discharging their duties adequately and diligently. Noting that the time requirement of each directorship varies, the Nominating Committee believes that limiting the number of directorships a Director can hold may be arbitrary. Instead, the Nominating Committee is provided a confirmation by each of the Directors of their ability to devote sufficient time and attention to the Company's affairs, having regard to all other commitments which they declare. The Nominating Committee is satisfied that all Directors have discharged their duties adequately and diligently from 1 January 2018 until the end of the financial year under review, and will continue to do so in the next financial year.

Alternate Director

Concurrent with his appointment as Executive Director of the Company and in view of his overseas commitments pertaining to the Group, Chief Executive Officer Kelvin Tang has appointed Kiran Raj as his Alternate Executive Director, with effect from 9 November 2017. Kiran Raj, who is concurrently the Chief Financial Officer, is familiar with the Company's affairs and is appropriately qualified.

Succession Planning for the Board and Management Team

Emphasis on succession planning ensures seamless transition and the Nominating Committee seeks to refresh the Board membership progressively and in an orderly manner. The Nominating Committee reviews succession and leadership development plans for the Board and management, which are subsequently approved by the Board.

Criteria and Process for Nomination and Selection of New Directors

A formal process is adopted in the search for and nomination and selection of new Directors. The Nominating Committee identifies the main attributes required of an incoming director based on the composition and skill set of the existing Board. The Nominating Committee will draw on the resources of Directors' personal and business contacts and recommendations of candidates during a shortlisting process. Recruitment agencies may also be used. Interviews will be held between potential candidates and Nominating Committee members before a recommendation is made to the Board.

Key Information on Directors

Please refer to the sections entitled "Board of Directors" and "Additional Information on Directors Seeking Re-appointment" of this Annual Report for key information on Directors. The Notice of Annual General Meeting sets out the Directors proposed for retirement and re-election at the AGM.

Principle 5

Board and Committee Evaluation

Board and Committee Evaluation

The Boards undertakes a formal annual assessment of its effectiveness as a whole, and that of each of its Committees and individual directors. An independent consultant Boardroom Corporate & Advisory Services Pte Ltd, is engaged to ensure that the Board and Committee assessments are completed promptly, fairly and confidentially.

The independent consultant works together with the Nominating Committee to design and update questionnaires for the evaluation process. Developed by incorporating the best practices in the market on Board and Committee evaluations, and revised based on key focus issues and areas prescribed by the Board, the questionnaires are provided to the Directors on an annual basis. The performance criteria for the evaluations includes the size and composition, independence, processes, information and accountability, risk controls and internal management and standards of conduct, all of which are in accordance with the guidelines of the 2012 Code and the terms of reference of each of the Committees. The Company has also implemented an additional peer performance evaluation for each individual Director as a more sensitive measure to enhance corporate governance. The results are collated by the independent consultant and presented to the Nominating Committee.

The Nominating Committee has undertaken detailed discussions of the evaluation results and suggested improvements provided for the financial year ended 31 December 2018, and will work with the Board and each of the Committees to implement action plan(s) to address key concerns and focal areas.

Principle 6
Access to Information

Complete, Adequate and Timely Information

Board and Committee materials are distributed in advance and are accessible via an online application on mobile devices. The Company fully recognises that the flow of relevant information on an accurate and timely basis is critical for the Board to be effective in the discharge of its duties, and aims to provide information the week before any meetings.

Any additional material or information requested by the Directors is promptly furnished. Matters of a highly sensitive nature may be tabled at a meeting or discussed without any papers being distributed. Management, which provides additional insights into the matters at hand, will be present at the meeting. The Directors are fully acquainted with the relevant management personnel, Company Secretaries and internal and external auditors to facilitate direct and independent access to the same.

Board materials include, amongst others, minutes to the previous Board meetings, major operational and financial updates, background or explanations on matters brought before the Board for decision or information, including issues dealt with by management, relevant budgets, forecasts and projections. In respect of budgets, any material variance between projections and actual results is disclosed and explained to the Board.

Company Secretaries

The Company Secretaries administer, attend and prepare minutes of Board proceedings. They assist the Chairman to ensure that Board procedures are followed and regularly reviewed to facilitate the effective functioning of the Board, and that the Company's memorandum, Articles and relevant rules and regulations, including requirements of the Cayman Companies Law, Securities & Futures Act and Listing Manual of the SGX-ST, are complied with. They also assist the Chairman and the Board to implement and strengthen corporate governance practices and processes with a view to enhancing long-term shareholder value.

The appointment and removal of Company Secretaries are subject to the approval of the Board as a whole.

Independent Professional Advice

The Directors, whether as a group or individually, may seek and obtain independent professional advice to assist them in their duties, at the expense of the Company.

Principle 7
Remuneration Matters

Remuneration Committee

The Remuneration Committee is chaired by Duane Radtke and also comprises Alan Nisbet and Keith Pringle. The Remuneration Committee comprises entirely Non-executive Directors, all of which are independent.

The key terms of reference for the Remuneration Committee include:

- review and approval of the Company's policy for determining the remuneration of executives including that of the Chief Executive Officer and other key management executives (the "Senior Management");
- continued review of the appropriateness and relevance of the Company's executive remuneration policy and other benefit programs;
- consideration, review and approval and/or varying the entire specific remuneration package and service contract terms for Senior Management;
- consideration, review and approval and/or adaptation (if necessary) of the entire specific remuneration package and service contract terms for each member of Senior Management (including Directors' fees, salaries, allowances, bonuses, payments, options, share-based incentives and awards, benefits in kind, retirement rights, severance packages and service contracts) having regard to the executive remuneration policy for each of the companies within the Group;
- consideration and approval of termination payments, retirement payments, gratuities, ex-gratia payments, severance payments and other similar payments to members of the Board and Senior Management, including the Chief Executive Officer;
- review of the Company's obligation arising in the event of termination of Executive Directors and Senior Management personnel's contracts of service, to ensure that such contracts of service contain fair and reasonable termination clauses which are not overly generous;
- review and approval of all option plans, stock plans and/or other equity based plans;
- annual determination whether awards will be made under each of the existing equity-based plans;
- review and approval of each award as well as the total proposed awards under each plan in accordance with the rules governing each plan;

- on-going review and approval of performance hurdles and/or fulfilment of performance hurdles for each of our equity-based plans; and
- review of succession plans for Senior Management positions.

The Remuneration Committee's recommendations are submitted for endorsement by the Board, thus assisting the Board to ensure that remuneration policies and practices are competitive within the industry in order to attract, retain and motivate employees, without being excessive, and thereby maximising shareholder value. No member of the Remuneration Committee is involved in deliberations in respect of any remuneration, compensation, options or any form of benefits to be granted to him. Where necessary, the Remuneration Committee may seek advice from independent expert remuneration consultants on remuneration matters, such as Towers Watson. Please refer to Principle 9 "Disclosure on Remuneration" of this corporate governance report for further information on the Company's compensation philosophy.

Principle 8
Level & Mix of Remuneration

Remuneration of Executive Directors and Senior Management

The remuneration packages of Executive Directors and Senior Management comprise the following components:

(a) Fixed and variable components

The fixed component consists of basic salary and Central Provident Fund contributions (if applicable). The Remuneration Committee ensures that Senior Management's remuneration is consistent and comparable with market practice by reviewing and considering such remuneration components against those of comparable companies, if such information is publicly available, while continuing to be aware of the general correlation between increased remuneration and performance improvements.

The variable component comprises variable bonus based on the Group's performance in relation to stipulated key performance indicators, as well as relevant market remuneration benchmarks. The performance of Senior Management is assessed every year. Total bonuses payable are reviewed by the Remuneration Committee and approved by the Board to ensure (i) alignment of interests with those of shareholders and (ii) symmetry with risk outcomes.

The Board views performance bonuses with a design to support the Group's business strategy and the enhancement of shareholder value through the annual fulfilment and delivery of financial, strategic and operational objectives. On an individual level, the performance bonus may vary based on the actual achievement of the Group and individual performance objectives. While these objectives may be of different emphasis for each executive, they are assessed on the same principles across business and strategy targets, which include environmental, health and safety processes; production, reserves and resource values; financial and risk management; and people development. Further, executives may be assessed on teamwork and collaboration across the Group.

(b) Allowances and benefits

Allowances and benefits provided are consistent with market practice and include medical benefits, flexible benefits and transportation and education allowances. Eligibility for these benefits and allowances depends on individual salary grade, employment position and country of residence.

(c) Share awards and options

In recognition of the contribution of Senior Management to the Company and as a tool for long-term incentivisation and alignment of interests with the Company, Senior Management is eligible for share options and awards under the KrisEnergy Employee Share Option Scheme ("KrisEnergy ESOS") and KrisEnergy Performance Share Plan ("KrisEnergy PSP").

For more information on KrisEnergy ESOS and KrisEnergy PSP and the share awards granted, please refer to the sections entitled "Directors' Report—KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan" and "Notes to the Consolidated Financial Statements—Share-based Payments" of this Annual Report.

The Remuneration Committee has the discretion not to award performance bonuses or share-based incentives in any year if any executive is involved in misconduct which has a material impact on our Company.

Remuneration of Non-Executive Directors

The Chairman of each Committee commands a higher fee in view of the greater responsibility carried by that office. Each Non-executive Director is paid a basic fee and an attendance fee. Executive Directors are not paid Directors' fees. Fees payable to Non-executive Directors are paid in cash and are subject to shareholders' approval at each AGM.

Basic fee

The basic fee structure of the Non-executive Directors is as disclosed in Table 2.

Since 2016, there has been a 25% reduction in the total remuneration of the Non-executive Directors as one of several cost-cutting measures to aid the Company through the adverse macroeconomic conditions and its volatile financial position. As the industry outlook remains unstable, the reduced remuneration has since been approved as the basic fee structure.

Table 2: Non-Executive Directors' Fees

Nature	Description	Rate
		US$
Board Fees	Chairman Fee	$15,000 per annum
	Basic Retainer Fee	$37,500 per annum
Audit and Risk Management Committee Fees	Membership Fee	$7,500 per annum
	Chairman Fee	$7,500 per annum
Remuneration Committee Fees	Membership Fee	$7,500 per annum
	Chairman Fee	$7,500 per annum
Nominating Committee Fees	Membership Fee	$7,500 per annum
	Chairman Fee	$7,500 per annum

If a Director occupies a position for part of the financial year, the fee payable will be pro-rated accordingly.

Attendance fee

A Non-executive Director will be paid an attendance fee of US$7,500 for each Board meeting attended (whether in person or by teleconference) in that financial year and will also be reimbursed any travel expenses incurred in relation thereto. No attendance fee is payable for attendance of (i) routine Board telephone conference calls or (ii) Committee meetings.

Principle 9

Disclousure on Remuneration

Annual Remuneration Report

A breakdown showing the level and mix of individual Director's and Senior Management's remuneration payable for the financial year under review is as disclosed in Table 3 and Table 4.

Bonuses

As disclosed in Table 3 below, a special bonus was declared for the financial year ended 31 December 2018, to recognise employees' contribution to the Company's sustainability over the last four years.

Share Awards and Options

Non-executive Directors are eligible for the grant of share options and awards under KrisEnergy ESOS and KrisEnergy PSP and are encouraged to acquire Shares in order to align their interests with those of shareholders. Directors' shareholding interests are disclosed in the section entitled "Directors' Report—Directors' interests in shares and debentures" of this Annual Report. For the financial year under review, Non-executive Directors will not receive any share options or awards as part of their remuneration. The Remuneration Committee will continue to review and consider the possibility of including a share-based component in the Non-executive Directors' remuneration for future years.

Disclosure of the (i) precise remuneration amounts of individual Executive Directors and Senior Management, and (ii) aggregate total remuneration paid to Senior Management is disadvantageous to the Group's business interests in view of the shortage of talented and experienced personnel in the upstream oil and gas industry.

No termination, retirement or post-employment benefits have been granted to the Directors or Senior Management for the financial year ended 31 December 2018.

Remuneration of Employees who are Immediate Family Members of a Director or the Chief Executive Officer

No employee of the Company and its subsidiaries is an immediate family member of a Director or the Chief Executive Officer. The remuneration packages of the Directors and Senior Management have been reviewed and approved by the Remuneration Committee, having regard to their contributions as well as the financial performance and commercial needs of the Group. The Remuneration Committee is satisfied and has ensured that the Directors and Senior Management are adequately, but not excessively, remunerated.

Details of KrisEnergy ESOS and KrisEnergy PSP

For more information of KrisEnergy ESOS and KrisEnergy PSP, please refer to the sections entitled "Directors' Report—KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan" and "Notes to the Consolidated Financial Statements—Share-based Payments" of this Annual Report.

Since 2016, Senior Management has undertaken a 10.0% to 25.0% reduction in remuneration packages and such reduced remuneration has since been approved as the new basic fee structure as a continued cost-cutting measure in light of the unstable industry outlook.

Table 3: Directors

Remuneration Bands	Salary Including CPF, If Any	Bonus/ Profit-sharing	Allow-ances & Others	Directors' Fees	Perfor-mance Shares	Total
	%	%	%	%	%	%
S$750,000 to S$1,000,000						
Kiran Raj[1]	80	10	10	–	–	100
$500,000 to S$750,000						
Kelvin Tang[2]	85	–	5	–	10	100
Below S$250,000						
John Koh	–	–	–	100	–	100
Duane Radtke	–	–	–	100	–	100
Tan Ek Kia	–	–	–	100	–	100
Alan Nisbet	–	–	–	100	–	100
Keith Pringle	–	–	–	100	–	100
Chris Ong Leng Yeow[3]	–	–	–	100	–	100
Chan How Chew[4]	–	–	–	100	–	100
Michael Chia[5]	–	–	–	–	–	–

NOTES:
1 Alternate Executive Director to Kelvin Tang Includes remuneration received as Chief Financial Officer
2 Includes remuneration received as Chief Executive Officer
3 Appointed to the Board on 5 January 2018
4 Resigned from the Board on 31 December 2018
5 Resigned from the Board on 5 January 2018

Table 4: Senior Management

Remuneration Bands	Designation	Base / Fixed Salary Including CPF. If any	Bonus/ Profit -Sharing	Allowance & Others	Perfor-mance Shares	Total
	%	%	%	%	%	%
S$500,000 to S$750,000						
James Parkin	Chief Operations Officer[1] (formerly Vice President Exploration)	85	–	5	10	100
Brian Helyer	Vice President Operations	85	4	11	–	100
Tim Kelly	Vice President Engineering	85	–	5	10	100
Mike Whibley	Vice President Technical	84	–	5	11	100
Chris Wilson	Vice President Commercial	77	–	11	12	100

NOTE:
1 Appointed as Chief Operating Officer on 1 January 2019

Principle 10
Accountability and Audit

Accountability and Audit

By understanding its responsibility and embracing openness and transparency in the conduct of the Company's affairs, whilst preserving commercial interests, the Board has adopted a balanced and understandable assessment of the Group's performance, position and prospects when presenting interim and other price-sensitive public reports and reports to regulators (if required).

Financial statements and reports, along with all other price sensitive information, are released to all shareholders through timely announcements on SGXNet, press releases, the corporate website and during teleconference briefings and investor forums. The Board takes steps to ensure compliance with legislative and regulatory requirements, including requirements under the listing rules. Regular updates on any material changes in the relevant legislative and regulatory frameworks are sent to the Board.

Principle 12
Audit and Risk Management Committee

Audit and Risk Management Commitee

The Audit and Risk Management Committee is chaired by John Koh and comprises Tan Ek Kia, Alan Nisbet and Keith Pringle. The Audit and Risk Management Committee comprises entirely of Non- executive Directors, all of which are independent.

The key terms of reference for the Audit and Risk Management Committee include:

- review of all financial information and any public financial reporting with management and external auditors for submission to the Board;
- review of significant financial reporting issues and judgements to ensure the integrity of financial statements and any announcements relating to financial performance;
- review of, together with external auditors, the audit plan, audit report, management letter and the responses which the external auditors have received from management on difficulties encountered with Management in the course of the audit;

- review of, together with external and internal auditors and reporting to the Board at least annually, the adequacy and effectiveness of the risk management and internal controls systems, including financial, operational, compliance and information technology controls;
- review of, together with internal auditors, the program, scope of results of the internal audit and management's response to findings to ensure that appropriate follow-up measures are taken;
- review at least annually, the adequacy and effectiveness of the internal audit function;
- review of the scope and results of the external audit, and the independence and objectivity of the external auditors;
- review of, together with external auditors, the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- review of interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interest are in place;
- assessment of the suitability of an accounting firm as external auditors and recommending to the Board the appointment or re-appointment of such external auditors, approving their compensation and reviewing and approving their discharge;
- review of filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure;
- commissioning and reviewing any findings of internal investigations into matters where there is suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material to the Group;
- obtaining recommendations on risk tolerance and strategy from management, and where appropriate, reporting and recommending to the Board for its determination the nature and extent of significant risks which the Group may take in achieving strategic objectives and the Group's overall level of risk tolerance and risk policies;
- reviewing and discussing, as and when appropriate, with management, the Group's risk governance structure and framework, including risk policies, risk mitigation and monitoring processes and procedures;review of quarterly reports from management regarding major risk exposures and steps taken to monitor, control and mitigate such risks;review of the Group's capability to identify and manage new risk types;
- review and monitor management's responsiveness to risks and matters identified;
- provide timely input to the Board on critical risk and regulatory compliance issues, material matters, findings and recommendations;
- review of risk management policies and guidelines and monitoring compliance therewith and assessing the adequacy and effectiveness of such risk management function;
- review of policy and arrangements by which staff and any other persons may, in confidence, raise concerns about possible improprieties in matters of financial reporting or other matters and ensure that arrangements are in place for such concerns to be raised and independently investigated, and for appropriate follow-up action to be taken;
- review and approval of any hedging policies and hedging instruments;
- reporting to the Board the work performed by the Audit and Risk Management Committee in carrying out its functions;
- monitoring investments in customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management or have shareholding interests in similar or related business of the Company and making assessments on whether there are any potential conflicts of interest;
- review of whistle-blower arrangements instituted by the Group through which staff may in confidence, raise concerns and possible improprieties in matters of financial or other matters; and
- undertake generally such other functions and duties as may be required by the Listing Manual of the SGX-ST and by amendments made thereto from time to time.

The Audit and Risk Management Committee has explicit authority to investigate any matter within its terms of reference, and has the full cooperation of and access to management. It also has direct access to the internal and external auditors, and full discretion to invite any Director or executive officer to attend its meetings. Its authority extends to reviewing its terms of reference and its own effectiveness annually and recommending necessary changes to the Board. The Audit and Risk Management Committee regularly meets with the external auditors and internal auditors, in each case without management's presence and at least once annually.

No member of the Audit and Risk Management Committee is a former partner or director of the Company's external auditing firm within the last two years, or holds any financial interest in the Company's external auditing firm. The Board is of the view that members of the Audit Committee and Risk Management Committee (including the Audit and Risk Management Committee Chairman) have recent and relevant accounting and related financial management expertise and are familiar with the Company's business and operations and are thus able to discharge their duties as Audit and Risk Management Committee members. Where possible, the Company arranges for sessions with the Company's external auditors to ensure that any changes to accounting standards and issues which have a direct impact on financial statements are highlighted to Audit and Risk Management Committee members and the Board.

External Auditors

The Audit and Risk Management Committee assesses the suitability of the external auditors and recommends to the Board the appointment, re-appointment and removal of the external auditors, and the remuneration and terms of engagement of the external auditors.

The Company's external auditors, Deloitte & Touche LLP, will hold office until the conclusion of the forthcoming AGM, and the re-appointment of Deloitte & Touche LLP is subject to shareholder approval at the AGM.

During the financial year under review, the Audit and Risk Management Committee Chairman, without the presence of management, held meetings with Deloitte & Touche LLP. The Audit and Risk Management Committee reviewed the independence and objectivity of Deloitte & Touche LLP through discussions with Deloitte & Touche LLP as well as a review of the volume and nature of non-audit services provided by Deloitte & Touche LLP during the period. Based on the review, the Audit and Risk Management Committee is satisfied that the financial, professional and business relationships between the Company and Deloitte & Touche LLP will not prejudice their independence and objectivity. Accordingly, the Audit and Risk Management Committee has recommended the re-appointment of Deloitte & Touche LLP at the forthcoming AGM.

In the financial year under review, the Audit and Risk Management Committee held discussions with management and Deloitte & Touche LLP regarding the accounting principles applied in the financial statements and any items that may affect the integrity of the financial statements.

Subsequently, the Audit and Risk Management Committee recommended to the Board the release of the full-year financial statements.

The total fees paid and/or payable to Deloitte & Touche LLP for the financial year under review are as disclosed in Table 5.

Table 5: Fees to External Auditors

Nature	S$'000	% Of Total Fees Paid
External Auditors' Fees For the Financial Year Under Review		
Total Audit Fees	471	100
Total Non-Audit Fees	–	–
Total Fees Paid	**471**	**100**

The Company has complied with Rules 712 and 715 of the Listing Manual of the SGX-ST in the appointment of its external auditors.

Whistle-Blowing Policy

The Audit and Risk Management Committee has put in place a whistle-blowing policy, containing clearly defined mechanisms and procedures to encourage and enable employees, customers or third parties to raise concerns internally and at a high level and report malpractices, impropriety and misconduct in the workplace without fear of reprisal. Concerns about possible improprieties in matters of financial malpractice or impropriety or fraud, dangers to environment health safety and/or security, criminal activity, improper conduct or unethical behaviour and other matters in breach of company policies can be raised confidentially to the Chairman of the Board or the General Counsel and arrangements are in place for independent investigations of such matters and for appropriate follow-up action. These procedures aim to promote accountability, transparency and consistency in dealing with concerns made in good faith. There were no whistle-blowing reports made during the financial year under review, save for a concern relating to procurement that has since been resolved.

Interested Person Transactions

The Company has embedded procedures to comply with the requirements of the Listing Manual of the SGX-ST relating to interested person transactions. All new Directors are briefed on the relevant provisions that they are required to comply with. Any interested person transactions are reported to, and monitored and reviewed by the Audit and Risk Management Committee.

During the financial year under review, the Company obtained shareholders' approval for the adoption of a general mandate for interested person transactions with Keppel Corporation Limited (and/or its subsidiaries) ("Interested Person Transactions Mandate") at an extraordinary general meeting held on 26 April 2018. The Interested Person Transactions Mandate will continue in force until the conclusion of the next AGM of the Company, and accordingly, renewal of the Interested Person Transactions Mandate will be sought at the forthcoming and each subsequent AGM of the Company.

Particulars of interested person transactions for the financial period under review as required under Rule 907 of the Listing Manual of the SGX-ST are set out in Table 6.

Table 6: Particulars of Interested Person Transactions

Name of interested person	Aggregate value of all interested person transactions during the financial period under review (excluding transactions less than S$100,000 and transactions conducted under shareholders' mandate pursuant to Rule 920)	Aggregate value of all interested person transactions conducted under shareholders' mandate pursuant to Rule 920 (excluding transactions less than S$100,000)
Keppel Corporation Limited (and/or its subsidiaries including Keppel Shipyard Limited)	Nil	S$30,000,000

Material Contracts (Rule 1207(8) of the Listing Manual of the SGX-ST)

There were no material contracts entered into by the Company or any of its subsidiaries involving the interest of the Chief Executive Officer, any Director, or controlling shareholder subsisting at the end of the financial year under review, save for the contract entered into with Keppel Shipyard Limited under the Interested Person Transactions Mandate of aggregate value S$30,000,000 for the modification and upgrading of the Company's production barge for the Apsara oil development in the Block A concession offshore Cambodia.

Principles 11 & 13

Risk Management & Internal Controls, Internal Audit

Risk Management and Internal Controls

It is the responsibility of the Board to ensure that there are sufficient risk governance measures implemented within the Company. The Board is also responsible for ensuring that management maintains a sound system of risk management and adequate and effective internal controls to safeguard shareholders' investments and the Group's assets. Risk management is a continuous process where Senior Management and operational managers continually participate to evaluate, monitor and report to the Audit and Risk Management Committee and the Board on significant risks encountered in operations.

The Company has developed and implemented a Board Assurance Framework (the "Framework"), which includes an enterprise risk management framework. The Framework acts as the platform for identification of significant and material risks, to assess the potential impact and likelihood of those risks occurring, test the internal control effectiveness and to create any action plans to further mitigate those risks. The risks identified in the Framework include strategic, financial, operational, compliance and information technology risks. A risk governance structure has been developed to provide details on the roles and responsibilities for the Board and management (specifically, the Chief Risk Officer) in risk monitoring, escalation, mitigation and reporting.

Risk appetite statements with tolerance limits are established to monitor shifts in significant risks and to proactively manage them within acceptable levels. These risk appetite statements have been reviewed and approved by the Audit and Risk Management Committee and the Board and are monitored on a quarterly basis. In addition, the Board has received assurance from (a) the Chief Executive Officer and Chief Financial Officer that the Company's financial records have been properly maintained and give a true and fair view of the Group's operations and finances, and (b) the CEO and other Senior Management who are responsible, regarding the adequacy and effectiveness of the Company's risk management and internal control systems.

The Audit and Risk Management Committee has the responsibility to oversee the Company's risk management framework and policies. Any material non-compliance or failures in internal controls and recommendations for improvements will be reported to the Audit and Risk Management Committee. The Audit and Risk Management Committee will also review the effectiveness of the actions taken by management on the recommendations made by the external and internal auditors.

Further, the Audit and Risk Management Committee will update the Board on such risk management framework and policies at least annually and from time to time when necessary.

Based on the internal controls established and maintained by the Group, work performed by independent external third parties, and reviews and assurances by management and various Board Committees, the Board with the concurrence of the Audit and Risk Management Committee is of the opinion that the Group's internal controls (including financial, operational, compliance and information technology controls) and risk management systems, which is relevant and material to the Group's current business scope and environment, was adequate and effective as at 31 December 2018. Nonetheless, it is understood that such a system can only provide reasonable, but not absolute, assurance that the Group will not be adversely affected by any event that could be reasonably foreseen as it strives to achieve its business objectives. The Board also notes that no system of internal controls and risk management can provide a complete assurance against human error, poor judgement in decision making, losses, fraud or other irregularities.

Internal Audit

Our internal audit functions within the Company ("Internal Auditors") are performed and maintained within the Company ("Internal Auditors").

The Internal Auditors are responsible for executing the Internal Audit Plan as approved by the Audit and Risk Management Committee and for reporting the findings and recommendations of such audits to the Audit and Risk Management Committee on a quarterly basis. The Internal Auditors' primary line of reporting is to the Chairman of the Audit and Risk Management Committee, although the function reports administratively to the Board. All internal audit summary reports are submitted to the Audit and Risk Management Committee for consideration, with copies of the reports extended to the Independent Non-executive Chairman, the Board (specifically, the Chief Executive Officer) and relevant Senior Management. To ensure timely and adequate closure of internal audit findings, the status of the implementation of the actions agreed by management is tracked and discussed with the Audit and Risk Management Committee.

The Internal Auditors have unrestricted direct access to the Audit and Risk Management Committee and unfettered access to all documents, records, properties and personnel, and has appropriate standing within the Company. The Internal Auditors' function is performed in accordance to the International Professional Practices Framework established by The Institute of Internal Auditors.

The Audit and Risk Management Committee approves the appointment, termination, evaluation and remuneration of the head of the internal audit function. The Audit and Risk Management Committee is also responsible for the review, at least annually, of the adequacy and effectiveness of the internal audit function. The Audit and Risk Management Committee believes that the current Internal Auditors have the relevant qualifications and experience, and the internal audit function is effective, adequately resources and independent of the activities it audits.

Principle 14

Shareholder Rights & Responsibilities

The Company believes in having a robust governance culture to ensure that shareholders receive fair and equitable treatment and have the opportunity to communicate their views on matters affecting the Company. The Company recognises that shareholders should be entitled to equal information rights and strives to provide adequate, timely and sufficient information pertaining to changes and updates in its business that could have a material impact on the share price and value. Such changes and updates could include financing arrangements, asset divestments and industry factors.

Shareholders whose names are registered in the CDP Register and the Register of Members are entitled to participate in, and vote at, shareholders' meetings. Shareholders are informed of shareholders' meetings through notices and/or circulars sent to all shareholders (including electronically) and/or published in newspapers, on the SGX-ST or on the Company's website. All shareholders have the opportunity to participate effectively in and vote at shareholders' meetings and will be informed of the rules, including voting procedures, which govern such shareholders' meetings. If any shareholder is unable to attend, he is allowed to appoint proxies to vote on his behalf at the meeting through proxy forms sent in advance. At shareholders' meetings, each distinct issue is proposed as a separate resolution and the results of the votes are announced at shareholders' meetings.

The Company advocates stakeholder participation and will hold shareholders' and/or noteholders' meetings in a central location in Singapore. Shareholders will be able to proactively engage Board and management on its business activities and financial performance.

Principle 15

Communication with Shareholders & Investors

The Company remains committed to delivering high standards of corporate disclosure and transparency through an open and non-discriminatory approach towards communications with shareholders and investors, the investment community and the media. The Company communicates regularly with its shareholders and provides regular and relevant information regarding the Company's performance, progress and prospects to aid shareholders and investors in their investmentb decisions. Where possible, the Company holds regular investor forums to provide information about its business and operations and the prevailing industry climate and also provide investors an avenue to raise any queries with management.

All press statements, financial results and material information are published on SGXNet and the Company's website www.krisenergy.com, and where appropriate, through media releases. The Company's announcements and website provide contact details for investors in the event they wish to contact the Company. In order to solicit and understand the view of stakeholders, briefing and/or teleconference sessions are conducted for the media, analysts and the investor community when quarterly financial results are released. Further, the Company arranges for investor meetings after the release of first half and full year financial statements and makes available the briefing slides for such meetings on its website and SGXNet.

Throughout the financial year, Management has participated in local and foreign investor meetings, conferences and forums, which provide a platform for Management to explain business strategy and financial performance. Management is provided with an opportunity to seek investor and analyst feedback and perceptions of the Company during these meetings, conferences and forums.

The Company is dedicated to facilitate communications with shareholders, the investor community, analysts and the media. Our investor relations responds to and ensures that all queries are addressed promptly.

No Dividend Policy

The Company does not have a fixed dividend policy. Taking into consideration factors including but not limited to its results of operations and cash flow, expected financial performance and working capital needs, future prospects, capital expenditures and other investment plans, other investment and growth plans, general economic and business conditions and other factors deemed relevant by the Board and statutory restrictions on the payment of dividends, the Company does not intend to pay dividends.

Principle 16

Conduct of Shareholder Meetings

Conduct of Shareholder Meetings

At each AGM, the Chairman will address the shareholders and present the progress and performance of the Group. The external auditors will be present to address shareholders' queries on the conduct of the audit and the preparation and content of the auditors' report. The Directors, chairpersons of each Board Committee, or members of the respective Committees standing in for them, will endeavour to be present at each AGM and other shareholders' meetings, if any, to address shareholders' queries. The Company will also ensure that appropriate management personnel will be present at each AGM and other shareholders' meetings, to respond to any shareholder enquiries.

A Company Secretary will prepare minutes of the shareholders' meetings, which will include any substantial comments or queries from shareholders and the corresponding responses from the Board and management. These minutes will be made available to shareholders upon request.

Each item of special business included in the notice of the shareholders' meeting will be accompanied by a full explanation of the effects of a proposed resolution. Separate resolutions are proposed for substantially separate issues at such meetings. Resolutions will be put to vote by electronic poll and detailed results showing the number of votes cast for and against each resolution and their respective percentage will be announced.

The Company is not implementing absentia voting methods such as voting via mail, email or fax until security, integrity and other pertinent issues are satisfactorily resolved.

SECURITIES DEALING

Securities Transactions Policy

The Company has adopted an internal policy which prohibits the Directors and officers and staff of the Group from dealing in the securities of the Company while in possession of price-sensitive information.

The Directors and officers are also discouraged from dealing in the Company's securities on short-term considerations and are prohibited from dealing in the Company's securities during the "black-out" period beginning two weeks before the announcement of the Company's quarterly financial statements and one month before the announcement of the Company's full-year financial statements, and ending on the date of the announcement of the relevant results.

Directors' Report and Consolidated Financial Statements

Directors' Report and Consolidated Financial Statements

THE DIRECTORS PRESENT HEREIN THEIR REPORT DATED 1 APRIL 2019, TOGETHER WITH THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS OF THE GROUP AND BALANCE SHEET AND STATEMENT OF CHANGES IN EQUITY OF THE COMPANY FOR THE FINANCIAL YEAR ENDED 31 DECEMBER 2018

01 Directors

The Directors in office at the date of this Directors' Report are:

Tan Ek Kia
Independent Non-Executive Chairman

Chris Ong Leng Yeow
Non-Executive Director

Alan Nisbet
Non-Executive Independent Director

Kelvin Tang
Chief Executive Officer, Executive Director and President, Cambodia

John Koh
Non-Executive Independent Director

Keith Pringle
Non-Executive Independent Director

Kiran Raj
Chief Financial Officer, Alternate Executive Director to Kelvin Tang and Vice President Finance and Administration

Duane Radtke
Non-Executive Independent Director

02 Audit and Risk Management Comittee

The Audit and Risk Management Committee comprises all Independent Directors. Members of the Audit and Risk Management Committee are:

John Koh
Chairman

Alan Nisbet

Tan Ek Kia

Keith Pringle

The Audit and Risk Management Committee carried out its function in accordance with the code of corporate governance 2012, including the following:

- review of all financial information and any public financial reporting with management and external auditors for submission to the Board;
- review of significant financial reporting issues and judgements to ensure the integrity of financial statements and any announcements relating to financial performance;
- review of, together with external auditors, the audit plan, audit report, management letter and the responses which the external auditors have received from management on difficulties encountered with management in the course of the audit;
- review of, together with external and internal auditors, and reporting to the Board at least annually, the adequacy and effectiveness of the risk management and internal controls systems, including financial, operational, compliance and information technology controls;
- review of, together with internal auditors, the program, scope of results of the internal audit and management's response to findings to ensure that appropriate follow-up measures are taken;
- review at least annually, the adequacy and effectiveness of the internal audit function;
- review of the scope and results of the external audit, and the independence and objectivity of the external auditors;
- review of, together with external auditor the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- review of interested person transactions for potential conflicts of interest as well as all conflicts of interests to ensure that proper measures to mitigate such conflicts of interest are put in place;
- assessment of the suitability of an accounting firm as external auditors and recommending to the Board the appointment or re-appointment of such external auditors, approving their compensation and reviewing and approving their discharge;
- review of filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure;
- commissioning and reviewing any findings of internal investigations into matters where there is suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material to the Group;
- obtaining recommendations on risk tolerance and strategy from management, and where appropriate, reporting and recommending to the Board for its determination the nature and extent of significant risks which the Group may take in achieving strategic objectives and the Group's overall level of risk tolerance and risk policies;
- reviewing and discussing, as and when appropriate, with management, the Group's risk governance structure and framework, including risk policies, risk mitigation and monitoring processes and procedures;
- review of quarterly reports from management regarding major risk exposures and steps taken to monitor, control and mitigate such risks;
- review of the Group's capability to identify and manage new risk types;
- review and monitor management's responsiveness to risks and matters identified;
- provide timely input to the Board on critical risk and regulatory compliance issues, material matters, findings and recommendations;
- review of risk management policies and guidelines and monitoring compliance therewith and assessing the adequacy and effectiveness of such risk management function;
- review of policy and arrangements by which staff and any other persons may, in confidence, raise concerns about possible improprieties in matters of financial reporting or other matters and ensure that arrangements are in place for such concerns to be raised and independently investigated, and for appropriate follow-up action to be taken;
- review and approval of any hedging policies and hedging instruments;
- reporting to the Board the work performed by the Audit and Risk Management Committee in carrying out its functions;
- monitoring investments in customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management or have shareholding interests in similar or related business of the Company and making assessments on whether there are any potential conflicts of interest;
- review of whistle-blower arrangements instituted by the Group through which staff may in confidence, raise concerns and possible improprieties in matters of financial or other matters; and
- undertake generally such other functions and duties as may be required by the Listing Manual of the SGX-ST and by amendments made thereto from time to time.

The Audit and Risk Management Committee has recommended to the Board of Directors the nomination of Deloitte and Touche LLP for re-appointment as external auditors at the forthcoming Annual General Meeting of the Company.

03 Arrangements to Enable Directors to Acquire Shares and Debentures

Neither at the end of the financial year nor at any time during the financial year did there subsist any arrangement whose object is to enable the Directors of the Company to acquire benefits by means of the acquisition of Shares or debentures in the Company or any other body corporate other than the performance shares granted under the KrisEnergy PSP.

04 Directors' Interest in Shares and Debentures

The interests of Directors holding office at the beginning and end of the financial year in the share capital of the Company or its related corporations according to the Register of Directors' Shareholdings kept by the Company were as follows:

	HOLDINGS REGISTERED IN NAME OF DIRECTORS OR NOMINEES		HOLDINGS IN WHICH DIRECTORS ARE DEEMED TO HAVE AN INTEREST	
Name of Director	**As at 31 December 2018**	**As at 1 January 2018 or date of appointment, if later**	**As at 31 December 2018**	**As at 1 January 2018 or date of appointment, if later**
John Koh	142,000[1]	142,000	–	–
Duane Radtke	–	–	2,000,000[2]	2,000,000
Tan Ek Kia	142,000	142,000	–	–
Alan Nisbet	–	–	–	–
Keith Pringle	243,308[3]	243,308	–	–
Chan Hon Chew[4]	See footnote 4	–	See footnote 4	–
Kelvin Tang	1,392,185	1,041,525	The aggregate of: (i) up to one-ninth of 2.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (ii) up to 683,777 PSP Awards	The aggregate of: (i) up to one-ninth of 3.0% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied; and (ii) up to 683,777 PSP Awards
Kiran Raj (Alternate Director to Kelvin Tang)	892,565	892,565	Up to 1,153,416 PSP Awards	Up to 1,153,416 PSP Awards
Chris Ong Leng Yeow[5]	–	–	–	–
Michael Chia[6]	See footnote 6	50,000	See footnote 6	–

NOTES

1 Held through nominee, DBS Nominees Pte Ltd

2 Duane Radtke is deemed interested in the 2,000,000 Shares held by Radtke Investments L.P. ("RILP") as Duane Radtke and his wife are the general partners of RILP and each is able to make investment decisions for RILP. RILP is owned by Duane Radtke (4.0%) and his wife (4.0%) and their two sons (46.0% each)

3 Held through nominee, TD Direct Investing (Europe) Ltd

4 Resigned from the Board on 31 December 2018

5 Appointed to the Board on 5 January 2018

6 Resigned from the Board on 5 January 2018

According to the Register of Directors' Shareholdings kept by the Company, there are no changes in any of the Directors' interests between the end of the financial year and 21 January 2019.

05 Directors' Receipt and Entitlement to Contractual Benefits

Since the end of the previous financial year, no Director has received or become entitled to receive a benefit by reason of a contract made by the Company or a related corporation with the Director or with a firm of which he is a member, or with a company in which he has a substantial financial interest, except as disclosed in the accompanying financial statements and in this Annual Report.

06 KrisEnergy Employee Share Option Scheme and KrisEnergy Performance Share Plan

The Remuneration Committee is responsible for administering the KrisEnergy ESOS and the KrisEnergy PSP. As at the date of this Directors' Report, the members of the Remuneration Committee are as follows:

Duane Radtke Chairman	**Alan Nisbet**
Chris Ong Leng Yeow	**Keith Pringle**

The KrisEnergy ESOS and KrisEnergy PSP were adopted on 10 July 2013, in conjunction with the initial public offering of the Company. The duration of these share-based incentive schemes is 10 years commencing from 10 July 2013.

The KrisEnergy ESOS and KrisEnergy PSP were established with the objective of rewarding, motiving and retaining our employees and Directors to achieve better performance. Through these share-based incentive schemes, we will be able to recognise and reward past contributions and services and motivate eligible employees and Directors to continue to strive for our long-term success.

RESTRICTIONS: The aggregate number of Shares which may be issued pursuant to the options and/or awards granted under the KrisEnergy ESOS and/or the KrisEnergy PSP, when added to the number of Shares issued and/or issuable in respect of all options and awards granted under the KrisEnergy ESOS and KrisEnergy PSP, shall not exceed 15% of the total issued share capital of the Company on the day immediately preceding the date of the relevant grant.

Unless otherwise decided by the Remuneration Committee, the entitlement to any share options or share awards is conditional on the continued employment of the eligible employee or Director up to the specified vesting date.

Special provisions for vesting and lapsing of awards granted under the KrisEnergy ESOS and KrisEnergy PSP apply for events such as the retirement, ill health or termination of employment and any other events approved by the Remuneration Committee. Upon the occurrence of such events, the Remuneration Committee will consider, at its discretion, whether or not to release any award, and will take into account circumstances of each individual case, including but not limited to the contributions made by that employee or Director

ELIGIBILITY: Employees who are not on probation and all Directors (including Non-executive or Independent Directors) of the Group who are in the employment of the Group are eligible to participate in the KrisEnergy ESOS and KrisEnergy PSP. Such an eligible participant must not be an undischarged bankrupt or have entered into a composition with his creditors.

Share Options

As at the date of this Directors' Report, the Company has not issued any share options pursuant to the KrisEnergy ESOS.

Share Awards

Participants of the KrisEnergy PSP will receive fully paid Shares free of charge, the equivalent in cash, or combinations thereof, provided that conditions are met within a prescribed performance period.

Since the commencement of the KrisEnergy PSP to the end of the financial year under review, PSP Awards comprising an aggregate 22,877,336 Shares have been granted to employees of the Company, including an aggregate of 8,425,241 Shares awarded to the then Executive Directors of the Company. There were no PSP Awards granted during the financial year under review.

In addition, awards have been granted under the KrisEnergy PSP on the Listing Date to certain Executive Directors and executive officers of the Company, subject to certain performance conditions being met and other terms and conditions. The maximum number of Shares that may be issued under the MS-Awards is 3% of the issued share capital of the Company. Under an MS-Award, each grantee has the conditional right to receive from the Company such number of Shares (fully paid up by the Company as required by law, as to par value) as represents up to one-ninth of 3% of the issued ordinary share capital of the Company.

Since the commencement of the KrisEnergy PSP to the end of the financial year under review, PSP Awards comprising (i) 16,642,144 Shares and (ii) eight-ninths of 0.5% of the issued share capital of the Company had vested. In respect of (i) 16,642,144 Shares were allotted and issued to employees, including 3,943,584 Shares to the then Executive Directors, and in respect of (ii) the Company has, in accordance with and as permitted under the terms of the MS-Awards, paid a cash sum equivalent to the aggregate market value of the Shares that would otherwise have been issued, including S$71,301.83 to an Executive Director. Share awards granted, vested and cancelled during the financial year and share awards outstanding as at the end of the financial year, are reflected in the table below:

DATE OF GRANT	TOTAL SHARE AWARDS GRANTED SINCE COMMENCEMENT OF KRISENERGY PSP TO END OF FINANCIAL YEAR UNDER REVIEW	TOTAL SHARE AWARDS VESTED SINCE COMMENCEMENT OF KRISENERGY PSP TO END OF FINANCIAL YEAR UNDER REVIEW	TOTAL SHARE AWARDS CANCELLED SINCE COMMENCEMENT OF KRISENERGY PSP TO END OF FINANCIAL YEAR UNDER REVIEW	BALANCE AS AT 1 JANUARY 2018	BALANCE AS AT 31 DECEMBER 2018
19 July 2013 (MS Awards) Directors					
Kelvin Tang	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	one-ninth of 0.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	–	up to one-ninth of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to one-ninth of 2.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
Others	up to seven-ninths of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	seven-ninths of 0.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	one-ninths of 0.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to seven-ninths of 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied	up to seven-ninths of 2.5% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
13 November 2013 Directors					
Kelvin Tang	235,553	235,553	–	–	–
Kiran Raj	256,967	256,967	–	–	–
Others	4,937,169	4,832,778	104,391	–	–
25 June 2014 Directors					
Kelvin Tang	235,553	–	–	235,553	235,553
Kiran Raj	256,967	_	–	256,967	256,967
Others	1,220,591	–	–	1,220,591	1,220,591
31 December 2014 Directors					
Kelvin Tang	448,224	–	–	448,224	448,224
Kiran Raj	896,449	–	–	896,449	896,449
Others	2,129,064	–	–	2,129,064	2,129,064
17 March 2015					
Employees	647,325	647,325	10,619	–	–
9 November 2015 Directors					
Kelvin Tang	432,598	432,598	–	–	–
Kiran Raj	432,598	432,598	–	–	–
Others	10,748,278	9,814,947	933,331	–	–

Save as disclosed in the table above, no Shares have been awarded under the KrisEnergy PSP to:

(a) any other Director of the Company;
(b) any Controlling Shareholder of the Company;
(c) any director or employee of any parent company and its subsidiaries; or
(d) any participant who has received Shares pursuant to the vesting of awards granted under the KrisEnergy PSP which, in aggregate, represents 5.0% or more of the total number of Shares available under the KrisEnergy PSP.

07 **Auditors**

Our auditors. Deloitte and Touche LLP, have expressed their willingness to accept re-appointment.

On behalf of the Board of Directors

Tan Ek Kia Director	1 April 2019, Singapore	**Kelvin Tang** Director	1 April 2019, Singapore

Statement by Directors

We, Tan Ek Kia and Kelvin Tang, being two of the directors of KrisEnergy Ltd. (the "Company"), do hereby state that, in the opinion of the directors,

(i) the accompanying financial statements of the Company and its subsidiaries (collectively, the "Group"), which comprise the statements of financial position of the Group and the Company as at 31 December 2018, the statements of changes in equity of the Group and the Company and the consolidated statement of comprehensive income and consolidated statement of cash flows of the Group for the year then ended together with notes thereto are drawn up so as to present fairly, in all material respects, the financial position of the Group and of the Company as at 31 December 2018 and the financial performance of the business, changes in equity and cash flows of the Group and the changes in equity of the Company for the year ended on that date, and

(ii) at the date of this statement, on the basis of successful negotiation and completion of matters disclosed in Note 1 to the financial statements, there are reasonable grounds to believe that the Group and the Company will be able to pay its debts as and when they fall due.

On behalf of the Board of Directors

Tan Ek Kia Director	1 April 2019, Singapore	**Kelvin Tang** Director	1 April 2019, Singapore

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF KRISENERGY LTD.

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of KrisEnergy Ltd. (the "Company") and its subsidiaries (the "Group"), which comprise the consolidated statement of financial position of the Group and the statement of financial position of the Company as at 31 December 2018, and the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows of the Group and the statement of changes in equity of the Company for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements of the Group and the statement of financial position and statement of changes in equity of the Company present fairly, in all material respects, the consolidated financial position of the Group and the financial position of the Company as at 31 December 2018 and the consolidated financial performance, consolidated changes in equity and consolidated cash flows of the Group and the changes in equity of the Company for the year then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with International Standards on Auditing ("ISAs"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Group in accordance with the Accounting and Corporate Regulatory Authority ("ACRA") *Code of Professional Conduct and Ethics for Public Accountants and Accounting Entities* ("ACRA Code") together with the ethical requirements that are relevant to our audit of the financial statements in Singapore, and we have fulfilled our other ethical responsibilities in accordance with these requirements and the ACRA Code. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material Uncertainty Related to Going Concern

We draw attention to Note 1 in the consolidated financial statements, which indicates that the Group has recorded losses of US$137.4 million for the year ended 31 December 2018 which resulted in Total Equity reducing to US$22.7 million as at 31 December 2018. As stated in Note 1 to the consolidated financial statements, these events or conditions, along with other matters as set forth in Note 1, indicate that a material uncertainty exists that may cast significant doubt on the Group's and the Company's ability to continue as a going concern. Our opinion is not modified in respect of this matter and our opinion remains unqualified.

Key Audit Matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current year. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. In addition to the matter described in the *Material Uncertainty Related to Going Concern* section, we have determined the matter described below to be the key audit matter to be communicated in our report.

Assessment of impairment in exploration and evaluation assets, oil and gas properties, and intangible assets

As at 31 December 2018, the Group recorded US$307.9 million of exploration and evaluation assets, US$163.8 million of oil and gas properties, US$8.4 million of intangible assets and US$13.5 million of other property, plant and equipment relating to the oil & gas assets (collectively the "Oil & Gas Assets"), which amount to approximately 77.0% of the Group's total assets.

Management assessed the recoverability of its Oil and Gas Assets by looking at future cash flows from the respective Oil & Gas Assets at 31 December 2018 and its future plans for these assets. They have also engaged an independent qualified person to estimate, where appropriate, the proved, probable and possible reserves for certain of the Oil & Gas Assets, including the future net cash flows arising from such.

The above assessment requires the exercise of significant judgement about and assumptions on, amongst others, the discount rate, oil reserves, expected production volumes and future Brent oil prices.

The Group has made disclosures on the above judgement in Note 3, and further disclosures in Note 11 to the financial statements.

How the audit matter was addressed in the audit

Our audit procedures focused on evaluating and challenging the judgements and key assumptions used by management in performing the impairment review. Such procedures included, amongst others:

- Evaluated the appropriateness of management's defined cash generating units ("CGU") in performing their impairment assessment;
- Reviewed management's budget and plan for the assets, including the funding options for future capital expenditure;
- Compared forecasted oil price assumptions to publicly available forecasts and other market data;
- Engaged our valuation specialists to independently develop expectations for the key macro-economic assumptions used in the impairment analysis, in particular the discount rate, and compared the independent expectations to those used by management;
- Reviewed the reserve reports prepared by independent qualified person relating to the Group's estimated oil reserves, including having a discussion of the reserve reports with the independent qualified person;
- Assessed the objectivity, competency and capability of the independent qualified person who prepared the reserve reports;
- Agreed the hydrocarbon production profile in the independent qualified person's reserve report to what management has used in their internal corporate financial model; and

- Reviewed the sensitivity tests performed by management on key variables such as (i) oil prices; (ii) discount rate; and (iii) production volume, keeping other assumptions constant.

We have also reviewed the adequacy of the Group's disclosures that has been set out in Note 11 to the financial statements.

Information Other than the Financial Statements and Auditor's Report Thereon

Management is responsible for the other information. The other information comprises the information, included in the annual report, but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of Management and Directors for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

The directors' responsibilities include overseeing the Group's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the Group audit. We remain solely responsible for our audit opinion.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with the directors, we determine those matters that were of most significance in the audit of the financial statements of the current year and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on Other Legal and Regulatory Requirements

The engagement partner on the audit resulting in this independent auditor's report is Mr Yang Chi Chih.

Deloitte & Touche LLP

Public Accountants and Chartered Accountants — Singapore, 1 April 2019

Consolidated Statement of Comprehensive Income

For the Financial Year Ended 31 December 2018

	NOTE	2018 US$	2017 US$
Revenue	6	144,805,416	140,700,213
Cost of sales	6	(149,562,608)	(144,243,061)
Gross loss		**(4,757,192)**	**(3,542,848)**
Other income	6	40,517,158	8,350,035
General and administrative expenses		(21,309,355)	(21,974,859)
Other operating expenses		(99,006,401)	(64,117,995)
Finance income		654,101	287,456
Finance costs	6	(49,261,437)	(53,834,112)
Loss before tax	6	**(133,163,126)**	**(134,832,323)**
Tax expense	7	(4,189,299)	(4,403,223)
Loss for the year		**(137,352,425)**	**(139,235,546)**
Other comprehensive income (loss)			
Items that may be reclassified subsequently to profit or loss			
Exchange differences on translation of foreign operations		(61,743)	(15,032)
Items that will not be reclassified subsequently to profit or loss			
Re-measurement of defined benefit obligations	20	181,290	(49,321)
Total comprehensive loss for the year		**(137,232,878)**	**(139,299,899)**
Loss per share attributable to owners of the Company (cents per share)			
Basic	6	(9)	(9)
Diluted	6	(9)	(9)

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

Statements of Financial Position

As at 31 December 2018

	NOTE	GROUP 2018 US$	GROUP 2017 US$	COMPANY 2018 US$	COMPANY 2017 US$
Non-current assets					
Exploration and evaluation assets	8	307,892,254	380,947,843	–	–
Oil and gas properties	9	163,769,685	177,540,886	–	–
Other property, plant and equipment	10	13,500,775	11,181,804	–	–
Intangible assets	11	8,444,892	8,444,892	–	–
Investment in subsidiaries	12	–	–	336,744,426	335,572,536
Other receivables	14	4,088,466	4,421,956	209,518,945	729,357,386
		497,696,072	582,537,381	546,263,371	1,064,929,922
Current assets					
Inventories	13	21,930,224	22,569,039	–	–
Trade and other receivables	14	37,950,868	59,863,162	–	–
Prepayments		5,686,060	739,025	143,777	101,809
Cash and bank balances	15	77,606,440	73,824,848	274,059	247,417
		143,173,592	156,996,074	417,836	349,226
Total assets		**640,869,664**	**739,533,455**	**546,681,207**	**1,065,279,148**
Equity					
Share capital	16	1,878,562	1,878,562	1,878,562	1,878,562
Share premium	16	730,302,151	730,302,151	730,302,151	730,302,151
Other reserves	16	30,707,795	30,524,522	41,312,447	41,067,431
Accumulated losses		(740,150,031)	(602,978,896)	(559,149,382)	(24,307,842)
Total equity		**22,738,477**	**159,726,339**	**214,343,778**	**748,940,302**
Non-current liabilities					
Employee benefit liability	20	611,635	1,630,812	–	–
Loans and borrowings	18	439,072,439	276,342,597	290,802,439	276,342,597
Derivative liabilities	22	2,966,741	7,321,468	2,966,741	7,321,468
Deferred tax liabilities	7	35,344,560	36,836,594	–	–
Provisions	19	22,206,613	42,675,146	–	–
Other payables	17	–	–	25,628,394	25,711,246
		500,201,988	364,806,617	319,397,574	309,375,311
Current liabilities					
Trade and other payables	17	73,545,266	44,199,730	11,062,831	5,923,545
Accrued operating expenses	17	21,935,797	19,486,897	1,877,024	1,039,990
Loans and borrowings	18	20,000,000	148,270,000	–	–
Withholding tax payable		197,753	215,244	–	–
Tax payable		2,250,383	2,828,628	–	–
		117,929,199	215,000,499	12,939,855	6,963,535
Total liabilities		**618,131,187**	**579,807,116**	**332,337,429**	**316,338,846**
Total equity and liabilities		**640,869,664**	**739,533,455**	**546,681,207**	**1,065,279,148**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

Statements of Changes in Equity

For the Financial Year Ended 31 December 2018

GROUP	SHARE CAPITAL	SHARE PREMIUM	ACCUMULATED LOSSES	FOREIGN CURRENCY TRANSLATION RESERVE	EMPLOYEE SHARE OPTION RESERVE	GENERAL RESERVE	TOTAL EQUITY
	US$	US$	US$	US$	US$	US$	US$
At 1 January 2018	1,878,562	730,302,151	(602,978,896)	(1,861,813)	767,095	31,619,240	159,726,339
Loss net of tax	–	–	(137,352,425)	–	–	–	(137,352,425)
Other comprehensive loss							
Exchange differences on translation of foreign operations	–	–	–	(61,743)	–	–	(61,743)
Re-measurement of defined benefit obligations	–	–	181,290	–	–	–	181,290
Total comprehensive loss for the year	–	–	(137,171,135)	(61,743)	–	–	(137,232,878)
Grant of equity-settled share transactions with employees (Note 21)	–	–	–	–	245,016	–	245,016
At 31 December 2018	**1,878,562**	**730,302,151**	**(740,150,031)**	**(1,923,556)**	**1,012,111**	**31,619,240**	**22,738,477**
At 1 January 2017	1,874,528	729,529,098	(463,694,029)	(1,846,781)	1,011,769	(8,681,096)	258,193,489
Loss net of tax	–	–	(139,235,546)	–	–	–	(139,235,546)
Other comprehensive loss							
Exchange differences on translation of foreign operations	–	–	–	(15,032)	–	–	(15,032)
Re-measurement of defined benefit obligations	–	–	(49,321)	–	–	–	(49,321)
Total comprehensive loss for the year	–	–	(139,284,867)	(15,032)	–	–	(139,299,899)
Grant of equity-settled share transactions with employees (Note 21)	–	–	–	–	531,161	–	531,161
Vesting of equity-settled share transactions with employees (Note 16)	4,020	771,815	–	–	(775,835)	–	–
Issuance of warrants	–	–	–	–	–	40,300,701	40,300,701
Issuance of shares on warrants exercised (Note 16)	14	1,238	–	–	–	(365)	887
At 31 December 2017	**1,878,562**	**730,302,151**	**(602,978,896)**	**(1,861,813)**	**767,095**	**31,619,240**	**159,726,339**

COMPANY	SHARE CAPITAL	SHARE PREMIUM	ACCUMULATED LOSSES	EMPLOYEE SHARE OPTION RESERVE	GENERAL RESERVE	TOTAL EQUITY
	US$	US$	US$	US$	US$	US$
At 1 January 2018	1,878,562	730,302,151	(24,307,842)	767,095	40,300,336	748,940,302
Loss net of tax	–	–	(534,841,540)	–	–	(534,841,540)
Other comprehensive income	–	–	–	–	–	–
Total comprehensive income for the year	–	–	(534,841,540)	–	–	(534,841,540)
Grant of equity-settled share transactions with employees (Note 21)	–	–	–	245,016	–	245,016
At 31 December 2018	**1,878,562**	**730,302,151**	**(559,149,382)**	**1,012,111**	**40,300,336**	**214,343,778**
At 1 January 2017	1,874,528	729,529,098	(43,811,011)	1,011,769	–	688,604,384
Profit net of tax	–	–	19,503,169	–	–	19,503,169
Other comprehensive income	–	–	–	–	–	–
Total comprehensive income for the year	–	–	19,503,169	–	–	19,503,169
Grant of equity-settled share transactions with employees (Note 21)	–	–	–	531,161	–	531,161
Vesting of equity-settled share transactions with employees (Note 16)	4,020	771,815	–	(775,835)	–	–
Issuance of warrants	–	–	–	–	40,300,701	40,300,701
Issuance of shares on warrants exercised (Note 16)	14	1,238	–	–	(365)	887
At 31 December 2017	**1,878,562**	**730,302,151**	**(24,307,842)**	**767,095**	**40,300,336**	**748,940,302**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

Consolidated Statement of Cash Flows

For the Financial Year Ended 31 December 2018

	NOTE	2018 US$	2017 US$
Operating activities			
Loss before tax		(133,163,126)	(134,832,323)
Adjustments to reconcile loss before tax to net cash flows			
Depreciation, depletion and amortisation		49,867,417	48,564,373
Dry hole expenses	6	11,450,524	–
Employee defined benefit		(555,709)	170,721
Equity-settled share transactions with employees	21	245,016	531,161
Gain on disposal of subsidiary	4	(2,526,714)	–
Impairment loss on exploration and evaluation assets	8	61,358,426	120,720,863
Impairment loss on oil and gas properties	9	18,946,687	–
Inventories written down	6	8,940,159	2,421,983
Write-off of joint operations receivables		–	6,160,000
Gain on de-recognition of 2017 Notes and 2018 Notes	6	–	(73,863,496)
Net fair value gain on financial instruments		(4,079,847)	(652,195)
Unrealised foreign exchange loss on financial instruments		(5,864,560)	16,397,749
Utilisation of decommissioning provisions	19	(3,971,874)	(2,431,897)
Write-back of unused decommissioning provisions	19	(29,006,833)	–
Unwinding of discount on decommissioning provisions	19	1,521,272	2,555,586
Unwinding of discount on Notes	6	20,049,522	22,450,169
Finance costs		27,690,643	28,828,357
Interest income		(654,101)	(287,456)
Operating cash flows before changes in working capital		20,246,902	36,733,595
Inventories		(12,736,309)	1,811,421
Trade and other receivables		18,653,268	7,900,077
Other current assets		–	1,919,653
Trade and other payables		30,438,381	(8,210,308)
Cash flows generated from operations		56,602,242	40,154,438
Interest received		654,101	287,456
Interest paid		(15,696,709)	(10,902,827)
Taxes paid		(6,259,578)	(6,456,350)
Net cash from operating activities		**35,300,056**	**23,082,717**

	NOTE	2018 US$	2017 US$
Investing activities			
Additions to exploration and evaluation assets	8	(22,284,978)	(37,758,376)
Farm-out of exploration and evaluation assets		–	22,105,464
Additions to oil and gas properties		(30,721,162)	(18,436,124)
Expenditure on assets refurbishment		(1,258,676)	(380,444)
Proceeds from disposal of other property, plant and equipment		–	915
Proceeds from sale of subsidiary	4	9,079,743	–
Purchase of other property, plant and equipment		(28,119)	(33,192)
Net cash used in investing activities		**(45,213,192)**	**(34,501,757)**
Financing activities			
Proceeds from warrants exercised		–	887
Proceeds from bank borrowings		55,000,000	43,000,000
Proceeds from Zero Coupon Notes		–	94,404,115
Financial restructuring expense		–	(7,809,836)
Repayment of bank borrowings		(35,000,000)	(83,000,000)
Payment of bond interest		(6,243,801)	(7,127,505)
Net cash from financing activities		**13,756,199**	**39,467,661**
Net increase in cash and cash equivalents		3,843,063	28,048,621
Effects of foreign exchange rate changes on the balance of cash held in foreign currencies		(61,471)	(16,112)
Cash and cash equivalents at beginning of year		65,554,848	37,522,339
Cash and cash equivalents at end of year	**15**	**69,336,440**	**65,554,848**

The accompanying accounting policies and explanatory notes form an integral part of the consolidated financial statements.

01 Corporate information

KrisEnergy Ltd. (the "Company") was incorporated on 5 October 2009 as a limited liability company in Cayman Islands. The Company is listed on the Singapore Exchange. The financial statements are expressed in United States Dollars ("USD" or "US$").

The registered office of the Company is located at 190 Elgin Avenue, George Town, Grand Cayman KY1-9005, Cayman Islands.

The principal activity of the Company is that of investment holding. The principal activities of the joint arrangements and subsidiaries are disclosed in Note 5 and Note 12 to the consolidated financial statements.

Material Uncertainty Related to Going Concern

The financial statements have been prepared on a going concern basis.

Although the Group benefitted from the general improvement in oil prices in 2018, the consequences of depressed and volatile oil markets from August 2014, coupled with the Group's high exposure to interest-bearing debts and associated non-cash finance charges, has materially and adversely impacted the Group's results of operations and financial condition.

The Group recorded net losses amounting to US$137.4 million for the financial year ended 31 December 2018, total equity was US$22.7 million and gearing was at 95.5% as at 31 December 2018. In addition, as at 31 December 2018, the Group has outstanding capital commitments (Note 23) that it will need to fulfill for the Group's oil & gas properties and exploration and evaluation assets.

To support the financial statements having been prepared on going concern basis and to ensure the adequacy of funds required to meet its obligations, working capital and capital commitment needs, the Group has prepared a 15-months consolidated cash flow forecast from 1 January 2019. In preparing the 15-months cash flow forecast, judgement and certain key assumptions have been taken into consideration by the Group, including:

(i) The Group has requested DBS Bank Ltd ("DBS") to provide additional funding of US$31.7 million via an upsize of the existing Revolving Credit Facility ("Additional Funding") and DBS continues to work with the Group on the Additional Funding, for a period and terms to be agreed;

(ii) The Group is in ongoing negotiations with material long-term vendors to significantly reduce and/or defer certain payment obligations. As at the date of the consolidated financial statements, the Group remains focused to achieve a positive outcome;

(iii) Oil prices continue to be volatile and in preparing the cash flow forecasts, the Group's average forecast for Brent Crude future prices for the next 12-15 months range from US$65 to US$70 per barrel;

(iv) As part of its continued effort to manage the Group's portfolio of assets, the Group is in discussion with a third party to divest and/or farm out certain of its interests in the Group's exploration and evaluation assets; and

(v) In relinquishing its interest in an exploration and evaluation asset, the Group has sought, and is currently pending approval from the relevant Government, to transfer unfulfilled capital commitments to another exploration and evaluation asset in which the Group has a working interest.

As at 31 December 2018 and as at the date of these consolidated financial statements, the Group remains overgeared and underequitised and as such, the Group has appointed financial advisors to formally evaluate and advise the Board on all available options to improve and strengthen the financial position of the Group ("Recapitalisation").

The above matters represent a material uncertainty that may cast a significant doubt on the Group's and the Company's ability to continue as a going concern, and therefore, the Group may not be able to realise its assets and discharge its liabilities in the normal course of business. Taking into account the underlying assumptions forming the cash flow projections of the Group as well as the Group's ongoing discussions with its major stakeholders, the Directors believe that positive outcomes relating to the matters stated above will enable the Group and the Company to continue operations for the foreseeable future, and that the basis of preparation of the accompanying consolidated financial statements remains appropriate.

For completeness, the accompanying consolidated financial statements do not include any adjustments relating to positive outcomes that may eventuate in connection with a Recapitalisation and nor do they include adjustments relating to the realisation and classification of asset and liability amounts that may be necessary if the Group is unable to continue as a going concern. If the going concern assumption is no longer appropriate, adjustments may have to be made to reflect the situation that assets may need to be realised other than in the normal course of business and at amounts which may differ significantly from the amounts at which they are currently recorded in the statements of financial position. In addition, the Group and the Company may have to reclassify non-current assets and liabilities as current assets and liabilities respectively. Such adjustments have not been made to these financial statements.

02 Summary of significant accounting policies

2.1 Basis of preparation

The consolidated financial statements of the Company and its subsidiaries (collectively the "Group"), have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by International Accounting Standards ("IAS") Board.

The consolidated financial statements have been prepared on the historical cost basis except as disclosed in the accounting policies below.

Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IAS 17 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories* or value-in-use ("VIU") in IAS 36 *Impairment of Assets.*

For financial reporting purposes, fair value measurements are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value measurements are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
(b) Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
(c) Level 3 inputs are unobservable inputs for the asset or liability.

2.2 Basis of consolidation

The consolidated financial statements comprise the financial statements of the Company and entities (including structured entities) controlled by the Company and its subsidiaries as at 31 December 2018. The financial statements of the subsidiaries used in the preparation of the consolidated financial statements are prepared for the same reporting date as the Company. Consistent accounting policies are applied to like transactions and events in similar circumstances.

Control is achieved when the Company:

- Has power over the investee;
- Is exposed, or has the rights, to variable return from its involvement with the investee; and
- Has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

When the Company has less than a majority of the voting rights of an investee, it has power over the investee when the voting rights are sufficient to give it the practical ability to direct the relevant activities of the investee unilaterally. The Company considers all relevant facts and circumstances in assessing whether or not the Company's voting rights in an investee are sufficient to give it power, including:

- The size of the Company's holding of voting rights relative to the size and dispersion of holdings of the other vote holders;
- Potential voting rights held by the Company, other vote holders or other parties;
- Rights arising from other contractual arrangements; and
- Any additional facts and circumstances that indicate that the Company has, or does not have, the current ability to direct the relevant activities at the time that decisions need to be made, including voting patterns at previous shareholders' meetings.

All intra-group balances, income and expenses and unrealised gains and losses resulting from intra-group transactions and dividends are eliminated in full.

Subsidiaries are consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date when such control ceases.

Losses within a subsidiary are attributed to the non-controlling interests even if that results in a deficit balance.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- De-recognises the assets (including goodwill) and liabilities of the subsidiary at their carrying amounts as at the date when control is lost;
- De-recognises the carrying amount of any non-controlling interest;
- De-recognises the cumulative translation differences recognised in equity;
- Recognises the fair value of the consideration received;
- Recognises the fair value of any investment retained;
- Recognises any surplus or deficit in profit or loss; and
- Re-classifies the Group's share of components previously recognised in other comprehensive income to profit or loss or retained earnings, as appropriate.

2.3 Adoption of new and revised IFRSs

In the current financial year, the Group has adopted all the new and revised IFRSs and IFRIC Interpretations ("IFRICs") that are relevant to its operations and effective for annual periods beginning on or after 1 January 2018. The adoption of these new/revised IFRSs and IFRICs resulted in changes to the Group's accounting policies but has no material effect on the amounts reported for the current or prior years. Effects for IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contract with Customers* are disclosed below:

IFRS 9 *Financial Instruments*

IFRS 9 introduces new requirements for (i) the classification and measurement of financial assets and financial liabilities, (ii) impairment of financial assets and (iii) general hedge accounting. Details of these new requirements as well as their impact on the financial statements are described below. The Group applied IFRS 9 with an initial application date of 1 January 2018. The Group has not restated the comparative information, which continues to be reported under IAS 39 as permitted under IFRS 9 transitional provision. The application of IFRS 9 on 1 January 2018 has no impact on the financial position of the Group with regard to classification and measurement of financial instruments nor has any material additional impairment been recognised upon application of expected loss approach as at same date. The accounting policies for financial instruments under IFRS 9 are set out in Note 2.13.

Classification and measurement of financial assets and financial liabilities

The Group has applied the requirements of IFRS 9 to instruments that have not been derecognised as at 1 January 2018 and has not applied the requirements to instruments that have already been derecognised as at 1 January 2018. The classification of financial assets is based on two criteria: the Group's business model for managing the assets and whether the instruments' contractual cash flows represent 'solely payments of principal and interest' on the principal amount outstanding. There are no changes in classification and measurement of the Group's financial assets and financial liabilities.

Impairment of financial assets

IFRS 9 requires an expected credit loss model as opposed to an incurred credit loss model under IAS 39. The expected credit loss model requires the Group to account for expected credit losses and changes in those expected credit losses at each reporting date to reflect changes in credit risk since initial recognition of the financial assets. It is no longer necessary for a credit event to have occurred before credit losses are recognised.

Specifically, IFRS 9 requires the Group to recognise a loss allowance for expected credit losses on (i) debt investments subsequently measured at amortised cost or at fair value through other comprehensive income ("FVTOCI"), (ii) lease receivables, (iii) contract assets and (iv) loan commitments and financial guarantee contracts to which the impairment requirements of IFRS 9 apply.

The adoption of IFRS 9 did not have a material impact on the financial performance or position of the Group.

IFRS 15 *Revenue from Contracts with Customers*

IFRS 15 supersedes IAS 11 *Construction Contracts*, IAS 18 *Revenue* and the related Interpretations. IFRS 15 introduces a 5-step approach to revenue recognition. The Group has applied IFRS 15 using the modified retrospective method with the cumulative effect of initially applying this Standard recognised at the date of initial application (1 January 2018) as an adjustment to the opening balance of retained earnings. Therefore, the comparative information was not restated and continues to be reported under IAS 11, IAS 18 and the related Interpretations. The Group has elected to apply this Standard retrospectively only to contracts that are not completed contracts at the date of initial application.

The Group's significant accounting policies for its revenue streams are disclosed in Note 2.19. The adoption of IFRS 15 did not have any impact on the financial performance or position of the Group.

2.4 New and revised IFRSs in issue but not yet effective

At the date of this report, the Group and the Company have not early applied the following new and revised IFRSs that have been issued but are not yet effective:

IFRS 16	*Leases*[1]
IFRS 17	*Insurance Contracts*[3]
IFRIC 23	*Uncertainty over Income Tax Treatments*[1]
Amendments to IFRS 3	*Definition of Business*[4]
Amendments to IFRS 9	*Prepayment Features with Negative Compensation*[1]
Amendments to IFRS 10 and IAS 28	*Sale or Contribution of Assets between an Investor and its Associate or Joint Venture*[2]
Amendments to IFRS 1 and IAS 8	*Definition of Material*[5]
Amendments to IAS 19	*Plan Amendment, Curtailment or Settlement*[1]
Amendments to IAS 28	*Long-term Interests in Associates and Joint Ventures*[1]
Amendments to IFRSs	*Annual Improvements to IFRS Standards 2015-2017 Cycle*[1]

NOTES

1 Effective for annual periods beginning on or after 1 January 2019.
2 Effective for annual periods beginning on or after a date to be determined.
3 Effective for annual periods beginning on or after 1 January 2021.
4 Effective for business combinations and asset acquisitions for which the acquisition date is on or after the beginning of the first annual period beginning on or after 1 January 2020.
5 Effective for annual periods beginning on or after 1 January 2020.

Management anticipates that the adoption of the above IFRSs, IFRICs, and amendments to IFRS and IAS in future periods will not have a material impact on the financial statements of the Group and of the Company in the period of their initial adoption except for the following:

IFRS 16 *Leases*

IFRS 16 introduces a comprehensive model for the identification of lease arrangements and accounting treatments for both lessors and lessees. IFRS 16 will supersede the current lease guidance including IAS 17 *Leases* and the related Interpretations when it becomes effective.

IFRS 16 distinguishes leases and service contracts on the basis of whether an identified asset is controlled by a customer. Distinctions of operating leases (off balance sheet) and finance leases (on balance sheet) are removed for lessee accounting, and is replaced by a model where a right-of-use asset and a corresponding liability have to be recognised for all leases by lessees (i.e. all on balance sheet) except for short-term leases and lease of low value assets.

The right-of-use asset is initially measured at cost and subsequently measured at cost (subject to certain exception) less accumulated depreciation and impairment losses, adjusted for any remeasurement of the lease liability. The lease liability is initially measured at the present value of the lease payments that are not paid at that date. Subsequently, the lease liability is adjusted for interest and lease payments, as well as the impact of lease modifications, amongst others. Furthermore, the classification of cash flows will also be affected as operating lease payments under IAS 17 are presented as operating cash flows; whereas under the IFRS 16 model, the lease payments will be split into a principal and an interest portion which will be presented as financing and operating cash flows respectively.

In contrast to lessee accounting, IFRS 16 substantially carries forward the lessor accounting requirements in IAS 17, and continues to require a lessor to classify a lease either as an operating lease or a finance lease.

Furthermore, extensive disclosures are required by IFRS 16.

As at 31 December 2018, the Group has non-cancellable operating lease commitments of US$70.6 million (2017: US$112.5 million). A preliminary assessment indicates that these arrangements may meet the definition of a lease under IFRS 16, and hence the Group may recognise a right-of-use asset and a corresponding liability in respect of all these leases unless they qualify for low value or short-term leases upon the application of IFRS 16. The new requirement to recognise a right-of-use asset and a related lease liability is expected to have an impact on the amount recognised in the Group's consolidated financial statements and the Group is currently assessing the potential impact including the transition options and practical expedients.

2.5 Business combination and goodwill

Business combinations are accounted for by applying the acquisition method. Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Acquisition-related costs are recognised as expenses in the periods in which the costs are incurred and the services are received.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration which is deemed to be an asset or liability, will be recognised in profit or loss.

The Group elects for each individual business combination, whether non-controlling interest in the acquiree (if any), that are present ownership interests and entitle their holders to a proportionate share of net assets in the event of liquidation, is recognised on the acquisition date at fair value, or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. Other components of non-controlling interests are measured at their acquisition date fair value, unless another measurement basis is required by another IFRS.

Any excess of the sum of the fair value of the consideration transferred in the business combination, the amount of non-controlling interest in the acquiree (if any), and the fair value of the Group's previously held equity interest in the acquiree (if any), over the net fair value of the acquiree's identifiable assets and liabilities is recorded as goodwill. In instances where the latter amount exceeds the former, the excess is recognised as excess of fair value of net assets acquired over consideration paid in profit or loss on the acquisition date.

Goodwill is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to the Group's cash generating units ("CGUs") that are expected to benefit from the synergies of the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

The CGUs to which goodwill have been allocated is tested for impairment annually and whenever there is an indication that the CGU may be impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU (or group of CGUs) to which the goodwill relates.

Where goodwill forms part of a CGU and part of the operation within that CGU is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative fair values of the operations disposed of and the portion of the CGU retained.

2.6 Subsidiaries

A subsidiary is an investee that is controlled by the Group. The Group controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

In the Company's separate financial statements, investment in subsidiaries are accounted for at cost less impairment losses.

2.7 Joint arrangements

A joint arrangement is a contractual arrangement whereby two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint arrangement is classified either as joint operation or joint venture, based on the rights and obligations of the parties to the arrangement.

To the extent the joint arrangement provides the Group with rights to the assets and obligations for the liabilities relating to the arrangement, the arrangement is a joint operation. To the extent the joint arrangement provides the Group with rights to the net assets of the arrangement, the arrangement is a joint venture.

The Group reassesses whether the type of joint arrangement in which it is involved has changed when facts and circumstances change.

Joint operations

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

The Group recognises in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation;
- Its share of the revenue from the sale of the output by the joint operation; and
- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenues and expenses relating to its interest in a joint operation in accordance with the IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When the Group enters into a transaction involving a sale or contribution of assets with a joint operation in which it is a joint operator, the Group recognises gains and losses resulting from such a transaction only to the extent of the interests held by the other parties of the joint operation.

When the Group enters into a transaction involving purchase of assets with a joint operation in which it is a joint operator, the Group does not recognise its share of the gains and losses until it resells those assets to a third party. When such transactions provide evidence of a reduction in the net realisable value of the assets to be purchased or of an impairment loss of those assets, the Group recognises its share of those losses.

When the Group enters into a transaction involving the transfer and assignment of working interest in which it is a joint operator with no consideration, the Group recognises gains resulting from such transaction only to the extent of the interests transferred and assigned to the Group, and when the transaction provides evidence of future economic benefits.

2.8 Foreign currency

The financial statements are presented in USD, which is also the Company's functional currency. Each entity in the Group determines its own functional currency and items included in the financial statements of each entity are measured using that functional currency.

Transactions and balances

Transactions in foreign currencies are measured in the respective functional currencies of the Company and its subsidiaries and are recorded on initial recognition in the functional currencies at exchange rates approximating those ruling at the transaction dates. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rates as at the dates of the initial transactions. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was measured.

Exchange differences arising on the settlement of monetary items or on translating monetary items at the end of the reporting period are recognised in profit or loss.

Consolidated financial statements

For the purpose of presenting consolidated financial statements, the assets and liabilities of foreign operations are translated into USD at the rate of exchange ruling at the end of the reporting period and their profit or loss are translated at the exchange rates prevailing at the date of the transactions. The exchange differences arising on the translation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

In the case of a partial disposal without loss of control of a subsidiary that includes a foreign operation, the proportionate share of the cumulative amount of the exchange differences are re-attributed to non-controlling interests and are not recognised in profit or loss.

2.9 Oil and natural gas exploration, evaluation and development expenditure

Oil and natural gas exploration, evaluation and development expenditure is accounted for using the successful efforts method of accounting.

Pre-licence costs

Pre-licence costs are expensed in the period in which they are incurred.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalised as intangible assets.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing.

If no future activity is planned or the licence has been relinquished or has expired, the carrying amount of the licence and property acquisition costs is written off through profit or loss. Upon production of first gas or oil, the relevant expenditure is transferred to oil and gas properties.

Exploration and evaluation costs

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource.

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalised as exploration and evaluation intangible assets until the drilling of the well is completed and the results have been evaluated. These costs include directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors.

If no potentially commercial hydrocarbons are discovered and evaluated results are not used in assessing the commerciality of the asset, the exploration and evaluation asset is written off through profit or loss as a dry hole expense. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be carried as an intangible asset while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as an intangible asset.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through profit or loss.

Upon production of first gas or oil, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Farm-outs - in the exploration and evaluation phase

The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal. The Group will test the retained interests for impairment if the terms of the arrangement indicate that the retained interest may be impaired.

Development costs

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development on delineation wells, is capitalised within exploration and evaluation assets, as management believes there are future economic benefits to be obtained for other wells.

2.10 Oil and gas properties and other property, plant and equipment

Initial recognition

Oil and gas properties and other property, plant and equipment are initially recorded at cost. Subsequent to recognition, other property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets (where relevant), borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalised value of a finance lease is also included within property, plant and equipment.

When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or expensed, except for costs which qualify for capitalisation relating to oil and gas properties asset additions, improvements or new developments.

Depreciation, depletion and amortisation

Oil and gas properties are depreciated, depleted and amortised on a unit-of-production basis over the total proved developed and undeveloped reserves of the asset concerned. Rights and concessions are depleted on the unit-of-production basis over the total proved developed and undeveloped reserves of the relevant area. The unit-of-production rate calculation for the depreciation, depletion and amortisation of asset development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure.

Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives which are as follows:

Renovation	–	3 Years
Furniture and fittings	–	3 Years
Office equipment	–	3 Years
Computers	–	2 Years

Refurbishment assets included in other property, plant and equipment are not depreciated as these assets are not yet available for use.

An item of property, plant and equipment and any significant part initially recognised is de-recognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on de-recognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in profit or loss when the asset is de-recognised.

The assets' residual values, useful lives and methods of depreciation, depletion and amortisation are reviewed at each reporting period, and adjusted prospectively, if appropriate.

Farm-outs - outside the exploration and evaluation phase

In accounting for a farm-out arrangement outside the exploration and evaluation phase, the Group:

- De-recognises the proportion of the asset that it has sold to the farmee;
- Recognises the consideration received or receivable from the farmee, which represents the cash received and/or the farmee's obligation to fund the capital expenditure in relation to the interest retained by the farmor;
- Recognises a gain or loss on the transaction for the difference between the net disposal proceeds and the carrying amount of the asset disposed of. A gain is only recognised when the value of the consideration can be determined reliably. If not, then the Group accounts for the consideration received as a reduction in the carrying amount of the underlying assets; and
- Tests the retained interests for impairment if the terms of the arrangement indicate that the retained interest may be impaired.

The consideration receivable on disposal of an item of property, plant and equipment or an intangible asset is recognised initially at its fair value by the Group. However, if payment for the item is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue. Any part of the consideration that is receivable in the form of cash is treated as a definition of a financial asset and is accounted for at amortised cost.

Major maintenance, inspection and repairs

Expenditure on major maintenance re-fits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset, that was separately depreciated and is now written off, is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised. Where part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s) which is immediately written off. All other day-to-day repairs and maintenance costs are expensed as incurred.

2.11 Intangible assets

Intangible assets acquired separately are measured initially at cost. Following initial acquisition, intangible assets are carried at cost less any accumulated amortisation and any accumulated impairment losses. Internally generated intangible assets, excluding capitalised development costs, are not capitalised and expenditure is reflected in profit or loss in the year in which the expenditure is incurred.

The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite useful lives are amortised over the estimated useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortisation period and the amortisation method are reviewed at least at each financial year-end. Changes in the expected useful life or the expected pattern of consumption of future economic benefits embodied in the asset is accounted for by changing the amortisation period or method, as appropriate, and are treated as changes in accounting estimates.

Intangible assets with indefinite useful lives or not yet available for use are tested for impairment annually, or more frequently if the events and circumstances indicate that the carrying amount may be impaired either individually or at the CGU level. Such intangible assets are not amortised. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the useful life assessment continues to be supportable. If not, the change in useful life from indefinite to finite is made on a prospective basis.

Gains or losses arising from de-recognition of an intangible asset are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognised in profit or loss when the asset is de-recognised.

2.12 Impairment of non-financial assets

The Group assesses at each reporting date whether there is an indication that an asset (or CGU) may be impaired. CGU is the smallest group of assets that independently generates cash flow and whose cash flows is largely independent of the cash flows generated by other assets, which include oil and gas properties, other property, plant and equipment, goodwill and other intangible assets. If any indication exists, or when an annual impairment testing for an asset is required, the Group makes an estimate of the asset's or CGU's recoverable amount.

An asset's recoverable amount is the higher of an asset's or CGU's fair value less costs of disposal and its VIU and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount.

In calculating VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. The Group bases its impairment calculation on detailed budgets and forecasts, which are prepared separately for each of the Group's CGU to which the individual assets are allocated. These budgets and forecasts generally cover the period up to the end of oil and gas field's economic life. VIU does not reflect future cash flows associated with improving or enhancing an asset's performance.

Impairment losses are recognised in profit or loss.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increase cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised previously. Such reversal is recognised in profit or loss.

2.13 Financial instruments

2.13.1 Financial assets (before 1 January 2018)

Initial recognition and measurement

Financial assets are recognised when, and only when, the Group becomes a party to the contractual provisions of the financial instrument. The Group determines the classification of its financial assets at initial recognition.

When financial assets are recognised initially, they are measured at fair value, plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

Subsequent Measurement

The subsequent measurement of financial assets depends on their classification, as follows:

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. This category includes derivative financial instruments entered into by the Group. Derivatives, including separated embedded derivatives are also classified as held for trading.

Subsequent to initial recognition, financial assets at fair value through profit or loss are measured at fair value. Any gains or losses arising from changes in fair value of the financial assets are recognised in profit or loss. Net gains or net losses on financial assets at fair value through profit or loss include exchange differences, interest and dividend income.

Loans and receivables

Non-derivative financial assets with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables. Subsequent to initial recognition, loans and receivables are measured at amortised cost using the effective interest method, less impairment. Gains and losses are recognised in profit or loss when the loans and receivables are de-recognised or impaired, and through the amortisation process.

The Group has not designated any financial asset upon initial recognition as held-to-maturity investments or available-for-sale financial assets.

De-recognition

A financial asset (or, where applicable a part of a financial asset or part of a group of similar financial assets) is de-recognised when:

- The Group transfers the contractual rights to receive the cash flows of the financial asset; or
- The Group retains the contractual rights to receive the cash flows of the financial asset, but assumes a contractual obligation to pay the cash flows to one or more recipients in a “past-through” arrangement; or
- The Group has transferred its rights to receive cash flows from the asset and either has transferred substantially all the risks and rewards of the asset, or has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

Where the Group has transferred its rights to receive cash flows from an asset and has neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognised to the extent of the Group’s continuing involvement in the asset. Continuing involvement that takes the form of a guarantee over the transferred asset, is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Group could be required to repay.

Where continuing involvement takes the form of a written and/or purchased option on the transferred asset, the extent of the Group’s continuing involvement is the amount of the transferred asset that the Group may repurchase, except that in the case of a written put option on an asset measured at fair value, the extent of the Group’s continuing involvement is limited to the lower of the fair value of the transferred asset and the option exercise price.

Impairment of financial assets

The Group assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Group first assesses whether objective evidence of impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be recognised are not included in a collective assessment of impairment.

If there is objective evidence that an impairment loss on financial assets carried at amortised cost has been incurred, the amount of the loss is measured as the difference between the asset’s carrying amount and the present value of estimated future cash flows discounted at the financial asset’s original effective interest rate. If a loan has a variable interest rate, the discount rate for measuring any impairment loss is the current effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. The impairment loss is recognised in profit or loss.

When the asset becomes uncollectible, the carrying amount of impaired financial asset is reduced directly or if an amount was charged to the allowance account, the amounts charged to the allowance account are written off against the carrying amount of the financial asset.

To determine whether there is objective evidence that an impairment loss on financial assets has been incurred, the Group considers factors such as the probability of insolvency or significant financial difficulties of the debtor and default or significant delay in payments.

If in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognised, the previously recognised impairment loss is reversed to the extent that the carrying amount of the asset does not exceed its amortised cost at the reversal date. The amount of reversal is recognised in profit or loss.

2.13.2 Financial assets (from 1 January 2018)

Financial assets are recognised on the statement of financial position when the Group becomes a party to the contractual provisions of the instruments.

Financial assets are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets (other than financial assets at fair value through profit or loss) are added to or deducted from the fair value of the financial assets, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets at fair value through profit or loss are recognised immediately in profit or loss.

Classification of financial assets

Debt instruments mainly comprise cash and bank balances and trade and other receivables that meet the following conditions and are subsequently measured at amortised cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Amortised cost and effective interest method

The effective interest method is a method of calculating the amortised cost of a debt instrument and of allocating interest income over the relevant period.

For financial instruments other than purchased or originated credit-impaired financial assets, the effective interest rate is the rate that exactly discounts estimated future cash receipts (including all fees and points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) excluding expected credit losses, through the expected life of the debt instrument, or, where appropriate, a shorter period, to the gross carrying amount of the debt instrument on initial recognition. For purchased or originated credit-impaired financial assets, a credit-adjusted effective interest rate is calculated by discounting the estimated future cash flows, including expected credit losses, to the amortised cost of the debt instrument on initial recognition.

The amortised cost of a financial asset is the amount at which the financial asset is measured at initial recognition minus the principal repayments, plus the cumulative amortisation using the effective interest method of any difference between that initial amount and the maturity amount, adjusted for any loss allowance. On the other hand, the gross carrying amount of a financial asset is the amortised cost of a financial asset before adjusting for any loss allowance.

Interest income is recognised using the effective interest method for debt instruments measured subsequently at amortised cost. For financial instruments other than purchased or originated credit-impaired financial assets, interest income is calculated by applying the effective interest rate to the gross carrying amount of a financial asset, except for financial assets that have subsequently become credit-impaired. For financial assets that have subsequently become credit-impaired, interest income is recognised by applying the effective interest rate to the amortised cost of the financial asset. If, in subsequent reporting periods, the credit risk on the credit-impaired financial instrument improves so that the financial asset is no longer credit-impaired, interest income is recognised by applying the effective interest rate to the gross carrying amount of the financial asset.

Foreign exchange gains and losses

The carrying amount of financial assets that are denominated in a foreign currency is determined in that foreign currency and translated at the spot rate as at each reporting date. Specifically, for financial assets measured at amortised cost that are not part of a designated hedging relationship, exchange differences are recognised in profit or loss in the "other operating expenses" line item.

Impairment of financial assets

The Group recognises a loss allowance for expected credit losses ("ECL") on trade and other receivables. The amount of expected credit losses is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

The Group recognises lifetime ECL for trade receivables. The expected credit losses on these financial assets are estimated using a provision matrix based on the Group's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate.

For all other financial instruments, the Group recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. If, on the other hand, the credit risk on the financial instrument has not increased significantly since initial recognition, the Group measures the loss allowance for that financial instrument at an amount equal to 12-month ECL. The assessment of whether lifetime ECL should be recognised is based on significant increase in the likelihood or risk of a default occurring since initial recognition instead of on evidence of a financial asset being credit-impaired at the reporting date or an actual default occurring.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12-month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

Significant increase in credit risk

In assessing whether the credit risk on a financial instrument has increased significantly since initial recognition, the Group compares the risk of a default occurring on the financial instrument as at the reporting date with the risk of a default occurring on the financial instrument as at the date of initial recognition. In making this assessment, the Group considers both quantitative and qualitative information that is reasonable and supportable, including historical experience and forward-looking information that is available without undue cost or effort. Forward-looking information considered includes the future prospects of the industries in which the Group's debtors operate, obtained from economic expert reports, financial analysts, as well as consideration of various external sources of actual and forecast economic information that relate to the Group's core operations.

In particular, the following information is taken into account when assessing whether credit risk has increased significantly since initial recognition:

- Existing or forecast adverse changes in business, financial or economic conditions that are expected to cause a significant decrease in the debtor's ability to meet its debt obligations;
- An actual or expected significant adverse change in the regulatory, economic, or technological environment of the debtor that results in a significant decrease in the debtor's ability to meet its debt obligations.

The Group presumes that the credit risk on a financial asset has increased significantly since initial recognition when contractual payments are more than 90 days past due, unless the Group has reasonable and supportable information that demonstrates otherwise.

The Group assumes that the credit risk on a financial instrument has not increased significantly since initial recognition if the financial instrument is determined to have low credit risk at the reporting date. A financial instrument is determined to have low credit risk if (i) the financial instrument has a low risk of default, (ii) the borrower has a strong capacity to meet its contractual cash flow obligations in the near term and (iii) adverse changes in economic and business conditions in the longer term may, but will not necessarily, reduce the ability of the borrower to fulfil its contractual cash flow obligations.

The Group regularly monitors the effectiveness of the criteria used to identify whether there has been a significant increase in credit risk and revises them as appropriate to ensure that the criteria are capable of identifying significant increase in credit risk before the amount becomes past due.

<u>Definition of default</u>

The Group considers the following as constituting an event of default for internal credit risk management purposes as historical experience indicates that receivables that meet either of the following criteria are generally not recoverable.

- When there is a breach of financial covenants by the counterparty; or
- Information developed internally or obtained from external sources indicates that the debtor is unlikely to pay its creditors, including the Group, in full (without taking into account any collaterals held by the Group).

Irrespective of the above analysis, the Group considers that default has occurred when a financial asset is more than 90 days past due unless the Group has reasonable and supportable information to demonstrate that a more lagging criterion is more appropriate.

<u>Credit-impaired financial assets</u>

A financial asset is credit-impaired when one or more events that have a detrimental impact on the estimated future cash flows of that financial asset have occurred. Evidence that a financial asset is credit-impaired includes observable data about the following events:

a) significant financial difficulty of the issuer or the borrower;
b) a breach of contract, such as a default or past due event; or
c) it is becoming probable that the borrower will enter bankruptcy or other financial reorganisation.

<u>Write-off policy</u>

The Group writes off a financial asset when there is information indicating that the counterparty is in severe financial difficulty and there is no realistic prospect of recovery, e.g. when the counterparty has been placed under liquidation or has entered into bankruptcy proceedings. Financial assets written off may still be subject to enforcement activities under the Group's recovery procedures, taking into account legal advice where appropriate. Any recoveries made are recognised in profit or loss.

<u>Measurement and recognition of expected credit losses</u>

The measurement of an ECL is a function of the probability of default, loss given default (i.e. the magnitude of the loss if there is a default) and the exposure at default. The assessment of the probability of default and loss given default is based on historical data adjusted by forward-looking information as described above. As for the exposure at default, for financial assets, this is represented by the assets' gross carrying amount at the reporting date.

For financial assets, the ECL is estimated as the difference between all contractual cash flows that are due to the Group in accordance with the contract and all the cash flows that the Group expects to receive, discounted at the original effective interest rate.

If the Group has measured the loss allowance for a financial instrument at an amount equal to lifetime ECL in the previous reporting period, but determines at the current reporting date that the conditions for lifetime ECL are no longer met, the Group measures the loss allowance at an amount equal to 12-month ECL at the current reporting date.

The Group recognises an impairment gain or loss in profit or loss for all financial instruments with a corresponding adjustment to their carrying amount through a loss allowance account.

De-recognition of financial assets

The Group de-recognises a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another party. If the Group neither transfers nor retains substantially all the risks and rewards of ownership and continues to control the transferred asset, the Group recognises its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all the risks and rewards of ownership of a transferred financial asset, the Group continues to recognise the financial asset and also recognises a collateralised borrowing for the proceeds received.

On de-recognition of a financial asset measured at amortised cost, the difference between the asset's carrying amount and the sum of the consideration received and receivable is recognised in profit or loss.

2.13.3 Equity instruments

An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all of its liabilities. Equity instruments are recorded at the proceeds received, net of direct issue costs.

Warrants

Detachable warrants issued are classified as equity. Warrants are measured at fair value at the date of grant and the proceeds are apportioned to warrants using the relative fair value approach.

2.13.4 Financial liabilities

Initial recognition and measurement

Financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets (other than financial liabilities at fair value through profit or loss) are added to or deducted from the fair value of the financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial liabilities at fair value through profit or loss are recognised immediately in profit or loss.

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading. Financial liabilities are classified as held for trading if they are acquired for the purpose of selling in the near term. This category includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Subsequent to initial recognition, financial liabilities at fair value through profit or loss are measured at fair value. Any gains or losses arising from changes in fair value of the financial liabilities are recognised in profit or loss.

Financial liabilities carried at amortised cost

Financial liabilities that are not carried at fair value through profit or loss are subsequently measured at amortised cost using the effective interest method. Gains and losses are recognised in profit or loss when the liabilities are de-recognised, and through the amortisation process.

De-recognition

A financial liability is de-recognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a de-recognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in profit or loss.

2.13.5 Embedded derivatives (before 1 January 2018)

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at fair value with changes in fair value recognised in profit or loss.

An embedded derivative is presented as a non-current asset or a non-current liability if the remaining maturity of the hybrid instrument to which the embedded derivative relates is more than 12 months and it is not expected to be realised or settled within 12 months. Other embedded derivatives are presented as current assets or current liabilities.

2.13.6 Embedded derivatives (from 1 January 2018)

Derivatives are initially recognised at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value as at each reporting date. The resulting gain or loss is recognised in profit or loss immediately unless the derivative is designated and effective as a hedging instrument, in which event the timing of the recognition in profit or loss depends on the nature of the hedge relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g. financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at fair value through profit or loss ("FVTPL"). Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated. The entire hybrid contract is classified and subsequently measured as either amortised cost or FVTPL as appropriate. See Note 2.13.2 for the Group's policy on classification of financial assets.

2.13.7 Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when the Group and the Company has a legally enforceable right to set off the recognised amounts; and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously. A right to set-off must be available today rather than being contingent on a future event and must be exercisable by any of the counterparties, both in the normal course of business and in the event of default, insolvency or bankruptcy.

2.14 Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and on hand, short-term deposits and amounts held under joint operations, which are subject to insignificant risk of changes in value.

2.15 Inventories

Inventories are stated at the lower of cost and net realisable value. Cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition. The drilling supplies and materials are accounted for on a first-in first-out basis and crude oil are determined based on a weighted average basis. Where necessary, allowance is provided for damaged, obsolete and slow moving items to adjust the carrying amount of inventories to the lower of cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and the estimated costs necessary to make the sale.

2.16 Leases

Operating lease payments are recognised as an operating expense in profit or loss on a straight-line basis over the lease term.

2.17 Provisions

General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and the amount of the obligation can be estimated reliably.

Provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate. If it is no longer probable that an outflow of economic resources will be required to settle the obligation, the provision is reversed. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. When discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

Decommissioning liability

The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/construction of the field. Any decommissioning obligations that arise through the production of inventory are expensed when the inventory item is recognised in cost of goods sold.

Changes in the estimated timing of decommissioning or changes to the decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to oil and gas assets.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying amount is taken immediately to profit or loss.

If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying amount of the asset, the Group considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the estimate for the revised value of oil and gas assets net of decommissioning provisions exceed the recoverable value, that portion of the increase is charged directly to expense.

Over time, the discount liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in profit or loss as a finance cost.

2.18 Hedge accounting

The Group applies hedge accounting for certain hedging relationships which qualify for hedge accounting.

For the purpose of hedge accounting, hedges are classified as fair value hedges when hedging the exposure to changes in the fair value of a recognised asset or liability or an unrecognised firm commitment.

At the inception of a hedging relationship, the Group formally designates and documents the hedging relationship to which the Group wishes to apply hedge accounting and the risk management objective and strategy for undertaking the hedge.

The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how the entity will assess the effectiveness of changes in the hedging instrument's fair value in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. Such hedges are expected to be highly effective in achieving offsetting changes in fair value or cash flows and are assessed on an ongoing basis to determine that they actually have been highly effective throughout the financial reporting periods for which they were designated.

Hedges which meet the strict criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in the fair value of a hedging derivative is recognised in profit or loss in other operating expenses. The change in the fair value of the hedged item attributable to the risk hedged is recorded as a part of the carrying amount of the hedged item and is also recognised in profit or loss in other operating expenses.

For fair value hedges relating to items carried at amortised cost, the adjustment to carrying amount is amortised through profit or loss over the remaining term of the hedge using the effective interest method. Effective interest rate amortisation may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged. If the hedged item is de-recognised, the unamortised fair value is recognised immediately in profit or loss.

When an unrecognised firm commitment is designated as a hedged item, the subsequent cumulative change in fair value of the firm commitment attributable to the hedged risk is recognised as an asset or liability with a corresponding gain or loss recognised in profit or loss.

2.19 Revenue recognition

2.19.1 Revenue recognition (before 1 January 2018)

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured, regardless of when the payment is made. Revenue is measured at the fair value of consideration received or receivable, taking into account contractually defined terms of payment and excluding taxes or duty.

Revenue from the sale of oil and gas is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil and gas, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts.

2.19.2 Revenue recognition (from 1 January 2018)

The Group recognises revenue from the sale of oil and gas. Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Group recognises revenue when it transfers control of a product to a customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism. Such revenue is recognised as a performance obligation satisfied at a point in time.

Revenue from the production of oil and gas, in which the Group and other partners jointly hold interests in, is recognised based on the Group's effective working interest and the terms of the relevant production sharing contracts.

2.20 Employee benefits

Defined contribution plans

The Group makes contributions to the defined contribution pension schemes. Contributions to defined contribution pension schemes are recognised as an expense in the period in which the related service is performed.

Employee leave entitlement

Employee entitlements to annual leave are recognised as a liability when they accrue to the employees. The estimated liability for leave is recognised for services rendered by employees up to the end of the reporting date.

Share-based payments

Employees (including senior executives) of the Group receive remuneration in the form of share-based payments, whereby employees render services as consideration for equity instruments (equity-settled transactions), and are granted share appreciation rights, which are settled in cash (cash-settled transactions).

Equity-settled transactions

The cost of equity-settled transactions is determined by the fair value at the date when the grant is made using an appropriate valuation model. That cost is recognised, together with a corresponding increase in employee share option reserve in equity, over the period in which the performance and/or service conditions are fulfilled in employee benefits expense. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimates of the number of equity instruments that will ultimately vest. The profit or loss expense or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period and is recognised in employee benefits expense in Note 21.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee as measured at the date of modification.

Cash-settled transactions

The cost of cash-settled transactions is measured initially at fair value at the grant date using a binomial model, further details of which are given in Note 21. This fair value is expensed over the period until the vesting date with recognition of a corresponding liability. The liability is re-measured to fair value at each reporting date up to, and including the settlement date, with changes in fair value recognised in employee benefits expense in Note 21.

Defined benefit plan

The Group operates defined benefit pension plans in Indonesia and Thailand, which are governed by the local labour laws.

The net defined benefit liability or asset is the aggregate of the present value of the defined benefit obligations (derived using a discount rate based on high quality corporate bonds) at the end of the reporting period reduced by the fair value of plan assets (if any) adjusted for any effect of limiting a net defined benefit asset to the asset ceiling. If there is no deep market for high quality corporate bonds, the Group derives the discount rate based on government bonds instead. The asset ceiling is the present value of any economic benefits available in the form of refunds from the plan or reductions in future contributions to the plan.

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method.

Defined benefit costs comprise the following:

- Service cost
- Net interest on the net defined benefit liability or asset
- Re-measurements of net defined benefit liability or asset

Service costs which include current service costs, past service costs and gains or losses on non-routine settlements are recognised as expense in profit or loss. Past service costs are recognised when plan amendment or curtailment occurs.

Net interest on the net defined benefit liability or asset is the change during the period in the net defined benefit liability or asset that arises from the passage of time which is determined by applying the discount rate based on high quality government bonds to the net defined benefit liability or asset. Net interest on the net defined benefit liability or asset is recognised as expense or income in profit or loss.

Re-measurements comprising actuarial gains and losses, return on plan assets and any change in the effect of the asset ceiling (excluding net interest on defined benefit liability) are recognised immediately in other comprehensive income in the period in which they arise. Re-measurements are recognised in retained earnings within equity and are not reclassified to profit or loss in subsequent periods.

Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the creditors of the Group, nor can they be paid directly to the Group. Fair value of plan assets is based on market price information. When no market price is available, the fair value of plan assets is estimated by discounting expected future cash flows using a discount rate that reflects both the risk associated with the plan assets and the maturity or expected disposal date of those assets (or, if they have no maturity, the expected period until the settlement of the related obligations).

The Group's right to be reimbursed of some or all of the expenditure required to settle a defined benefit obligation is recognised as a separate asset at fair value when and only when reimbursement is virtually certain.

2.21 Taxes

Current tax

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date in the countries where the Group operates and generates taxable income.

Current taxes are recognised in profit and loss except to the extent that the tax relates to items recognised outside profit or loss, either in other comprehensive income or directly in equity. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretations and establishes provisions where appropriate.

Deferred tax

Deferred tax is provided using the liability method on temporary differences at the end of the reporting period between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognised for all taxable temporary differences, except:

- Where the deferred tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognised for all deductible temporary differences, the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences, and the carry forward of unused tax credits and unused tax losses can be utilised, except:

- Where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available, against which the temporary differences can be utilised.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilised. Unrecognised deferred tax assets are reassessed at the end of each reporting period and are recognised to the extent that it has become probable that future taxable profits will be available to allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting date.

Deferred tax relating to items recognised outside profit or loss is recognised outside profit or loss. Deferred tax items are recognised in correlation to underlying transaction either in other comprehensive income or directly in equity and deferred tax arising from a business combination is adjusted against goodwill on acquisition.

Royalties, resource rent tax and revenue-based taxes

In addition to corporate taxes, the Group's consolidated financial statements also include and recognise taxes on income, other type of taxes on net income which are calculated based on oil and gas production.

Royalties, resource rent taxes and revenue-based taxes are accounted for under IAS 12 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government tax authority and the amount payable is based on taxable income - rather than based on physical quantity produced or as a percentage of revenue - after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are recognised as current provisions and included in cost of sales.

Production-sharing agreements

According to the production-sharing agreements ("PSA"), the share of the profit oil to which the government is entitled in any calendar year, is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities. This portion of tax and revenue are presented net in profit or loss.

03 Significant accounting judgements, estimates and assumptions

The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the disclosure of contingent liabilities at the end of each reporting period. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of the asset or liability affected in the future periods.

3.1 Judgements made in applying accounting policies

In the process of applying the Group's accounting policies, other than those disclosed in Note 1, management has made the following judgements, which have the most significant effect on the amounts recognised in the consolidated financial statements:

Hydrocarbon reserve and resource estimates

The Group has engaged an independent qualified person to estimate the proved, probable and possible reserves for certain of the Group's exploration and evaluation assets and oil and gas properties, and such reserves are determined in accordance with Society of Petroleum Engineers' rules and incorporating the estimated future cost of developing those reserves. The Group estimates its commercial reserves based on information compiled by the independent qualified person and internal experts relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates.

Recoverable reserves are determined by taking into consideration, amongst other factors, future development costs, discount rates, operating costs, decommissioning costs, exploration potential, and future hydrocarbon prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the PSA.

Future development costs are estimated using assumptions as to number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The oil price assumption is derived based on the average forecast for Brent Crude future prices and adjusted for quality, transportation fees and regional price differences. The Group's average forecast for Brent Crude future prices range from US$60 to US$80 (2017: US$60 to US$80) per barrel.

As the economic assumptions used may change and as additional geological information is obtained during the operation of an asset, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, including amongst others, on items such as (i) impairment assessment of the Group's exploration and evaluation assets, oil and gas properties, and intangible assets; (ii) depreciation, depletion and amortisation charges; (iii) inventory cost; (vi) provisions for decommissioning; and (iv) deferred tax assets.

3.2 Key sources of estimation uncertainty

The key assumptions concerning the future and other key sources of estimation uncertainty at the end of the reporting period are discussed below. The Group based its assumptions and estimates on parameters available when the financial statements were prepared. Existing circumstances and assumptions about future developments, however, may change due to market changes or circumstances arising beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

Recoverability of oil and gas assets

The Group assesses each asset or CGU at each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, a formal estimate of the recoverable amounts is made, which is considered to be the higher of fair value less costs to sell and VIU.

As discussed in Note 3.1, the Group has engaged an independent qualified person to estimate the proved, probable and possible reserves, including the future net cash flows arising from such. Management uses the valuation amounts to form the basis for their impairment review, and may adjust such valuation with other estimates which may include discount rates and development plans that are not covered by the independent qualified person. These estimates and assumptions are subject to risk and uncertainty. Changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGU.

The carrying amount of the Group's exploration and evaluation assets, oil and gas properties and intangible assets are disclosed in Notes 8, 9 and 11 to the financial statements respectively. The sensitivity analysis is disclosed in Note 11 to the financial statements.

Exploration and evaluation expenditures

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether it is likely that future economic benefits are likely, either from future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economical viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in profit or loss in the period when the new information becomes available.

Decommissioning costs

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the asset and could have a material impact on the Group's financial statements.

The carrying amount of the Group's provision for decommissioning is disclosed in Note 19 to the financial statements.

Fair value measurements

Some of the Group's assets and liabilities are measured at fair value for financial reporting purposes.

In estimating the fair value of an asset or a liability, the Group uses market-observable data to the extent it is available. Where Level 1 inputs are not available, the Group engages third party qualified valuers to perform the valuation. The management works closely with the qualified external valuers to establish the appropriate valuation techniques and inputs to the model. The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Information about the valuation techniques and inputs used in determining the fair value of various assets and liabilities are disclosed in Notes 18, 22 and 25 to the financial statements.

Taxes

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws, and the amount and timing of future taxable income. The Group has exposure to income taxes in various jurisdictions due to the wide range of international business relationships and the long-term nature and complexity of existing contractual agreements. Significant judgement is involved in determining the group-wide provision for income taxes and recoverability of certain tax from the tax authorities. The Group establishes provisions, based on reasonable estimates, for possible consequences of audits by the tax authorities of the respective counties in which it operates. When the final tax outcome of these matters is different from the amounts that were initially recognised, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made. Further details on taxes are disclosed in Note 7 to the financial statements.

Calculation of loss allowance

When measuring ECL, the Group uses reasonable and supportable forward-looking information, which is based on assumptions for the future movement of different economic drivers and how these drivers will affect each other.

Loss given default is an estimate of the loss arising on default. It is based on the difference between the contractual cash flows due and those that the Group would expect to receive, taking into account cash flows from collateral and integral credit enhancements.

Probability of default constitutes a key input in measuring ECL. Probability of default is an estimate of the likelihood of default over a given time period, the calculation of which includes historical data, assumptions and expectations of future conditions.

The carrying amounts of trade and other receivables are disclosed in Note 14 to the financial statements.

Impairment of investment in subsidiaries and amounts due from subsidiaries

The Company has reviewed the recoverability of the investment in subsidiaries and the amounts due from subsidiaries. As at 31 December 2018, the Company has recognised a loss allowance of US$508.9 million (2017: US$Nil) for amounts due from subsidiaries as these subsidiaries continued to make losses during the year. The carrying amount of investment in subsidiaries and amounts due from subsidiaries are disclosed in Notes 12 and 14 to the financial statements.

04 Disposal of subsidiary

Nong Yao G11 (Thailand) Ltd ["NYG11"]

On 22 June 2018, the Group completed its disposal of a 100% equity interest in Nong Yao G11 (Thailand) Ltd, which held a 22.5% working interest in the G11/48 Concession to Mubadala Petroleum ("MP"), for a consideration of US$13.3 million.

The carrying amount of the identifiable assets and liabilities of NYG11 as at date of disposal was:

	CARRYING AMOUNT ON DISPOSAL US$
Assets	
Oil and gas properties	17,070,849
Other receivables	1,521,103
Inventories	4,434,965
Prepayment	1,314,615
	24,341,532
Liabilities	
Trade and other payables	2,950,663
Accrued operating expenses	2,834,033
Provisions	7,813,570
	13,598,266
Total identifiable net assets at carrying amount	10,743,266
Consideration received in cash	9,079,743
Remaining consideration included in other receivables (Note 14)	4,190,237
Total consideration	13,269,980
Gain on disposal of subsidiary	2,526,714

05 Interests in oil and gas blocks

The Group holds interests in each contract area for the right to explore and produce oil and gas. The Group's interests in oil and gas blocks are listed in the following table.

For each contract area where the Group and other partners jointly hold interests in, the respective interests are accounted for as joint operations.

CONTRACT AREA (DATE OF EXPIRY)	HELD BY	DESCRIPTION	PLACE OF OPERATION	% OF EFFECTIVE WORKING INTEREST	
				2018	2017
G10/48 Concession (7 December 2035)	KrisEnergy (Gulf of Thailand) Ltd. (25.0%) and KrisEnergy G10 (Thailand) Ltd. (64.0%)	Exploration and production of petroleum under Concession Agreement with Department of Mineral Fuels	Gulf of Thailand	89.00	89.00
G11/48 Concession (12 February 2036)[1]	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Departmentof Mineral Fuels	Gulf of Thailand	–	22.50
Cambodia Block A PA (22 August 2042)	KrisEnergy (Cambodia) Ltd. (23.75%) and KrisEnergy (Apsara) Ltd. (71.25%)	Drilling of exploration wells under the Petroleum Agreement ("PA") with Cambodian Ministry of Mines and Energy	Offshore Cambodia	95.00	95.00
Kutai PSC (15 January 2037)[2]	KrisEnergy Kutai B.V. (24.6%) and KrisEnergy Kutei B.V. (30.0%)	Exploration and production of petroleum under Production Sharing Contract ("PSC") with Indonesia Governmental Authority	Indonesia	54.60	54.60
B8/32 Concession (31 July 2030)	KrisEnergy (Gulf of Thailand) Ltd./Orange Energy Ltd./ B8/32 Partners Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Fuels	Gulf of Thailand	4.63	4.63
B9A Concession (16 July 2041)[3]	KrisEnergy (Gulf of Thailand) Ltd./Orange Energy Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Fuels	Gulf of Thailand	4.63	4.63
Block 120 PSC (22 January 2039)[2]	KrisEnergy (Phu Khanh 120) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority	Offshore Vietnam	33.33	33.33
East Seruway PSC (12 November 2038)[2]	KrisEnergy East Seruway B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	100.00	100.00
Bulu PSC (13 October 2033)	KrisEnergy (Satria) Ltd.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	42.50	42.50
East Muriah PSC (12 November 2038)[2]	KrisEnergy (East Muriah) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	50.00	50.00
Bala-Balakang PSC (18 December 2041)	KrisEnergy (Bala-Balakang) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	85.00	85.00
Udan Emas PSC (19 July 2042)	KrisEnergy (Udan Emas) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	100.00	100.00
Block 9 PSC (26 August 2033)	KrisEnergy Bangladesh Limited	Exploration and production of petroleum under Production Sharing Contract with Bangladesh Governmental Authority	Bangladesh	30.00	30.00
G6/48 Concession (7 January 2036)[4]	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Fuels	Gulf of Thailand	43.00	30.00
Sakti PSC (25 February 2044)	KrisEnergy (Sakti) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	95.00	95.00
Block 115/09 PSC (30 March 2044)	KrisEnergy (Vietnam 115) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority	Offshore Vietnam	100.00	100.00
Block SS-11 PSC (11 March 2021)	KrisEnergy (Asia) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Bangladesh Governmental Authority	Bangladesh	45.00	45.00
Andaman II PSC (4 April 2048)	KrisEnergy (Andaman II) Ltd	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	30.00	–

NOTES

1 On 22 June 2018, KrisEnergy (Gulf of Thailand) Ltd. completed the disposal of Nong Yao G11 (Thailand) Ltd, which holds a 22.5% working interest in the G11/48 Concession (Note 4).

2 The contract area is pending relinquishment.

3 On 31 October 2017, B9A Concession ceased operations. Abandonment activities are underway before the contract area is relinquished.

4 The effective working interest represents the economic interest in the production area.

06 Loss before tax

The following items have been included in arriving at loss before tax

	GROUP	
	2018 US$	**2017** US$
Revenue		
Sale of crude oil	130,374,847	122,836,323
Sale of gas	14,430,569	17,863,890
	144,805,416	140,700,213
Cost of sales		
Depreciation, depletion and amortisation of oil and gas properties	(49,808,916)	(48,313,868)
Operating costs	(79,911,958)	(82,293,794)
Thai Petroleum royalties paid	(10,901,575)	(11,213,416)
Inventories written down (Note 13)	(8,940,159)	(2,421,983)
	(149,562,608)	(144,243,061)
Other income		
Gain on disposal of subsidiary (Note 4)	2,526,714	–
Joint operator overhead charges	1,471,313	1,280,386
Income from shared facilities in joint operations	434,225	475,065
Income from technical services provided to joint operations	2,381,903	2,496,287
Write-back of unused decommissioning provisions (Note 19)	29,006,833	–
Others	4,696,170	4,098,297
	40,517,158	8,350,035
General and administrative expenses are mainly made up of the following items		
Consultants' fees	(380,448)	(469,640)
Depreciation of other property, plant and equipment (Note 10)	(58,501)	(250,505)
Employee benefits expense		
Salaries and bonuses	(7,083,230)	(9,001,285)
Share-based payments (Note 21)	(912,504)	(473,162)
Central Provident Fund contributions	(242,364)	(127,781)
Employee defined benefit	629,096	(1,440,411)
Other short-term benefits	(387,701)	(650,510)
Operating lease expense	(610,388)	(594,247)
Professional fees	(2,244,931)	(4,428,810)
Other operating expenses are mainly made up of the following items		
Dry hole expenses (Notes 8 and 9)	(11,450,524)	–
Impairment losses on exploration and evaluation assets (Note 8)	(61,358,426)	(120,720,863)
Impairment losses on oil and gas properties (Note 9)	(18,946,687)	–
Write-off of joint operations receivables	–	(6,160,000)
Joint study expenses	(600,000)	(369,613)
Gain on de-recognition of 2017 Notes and 2018 Notes	–	73,863,496
Net fair value gain (loss) on embedded derivatives (Note 22)	4,079,847	(2,145,937)
Net fair value gain on hedge	–	2,798,132
Finance costs		
Financing fees	(3,002,007)	(8,785,214)
Interest on bank borrowings	(13,394,509)	(10,695,435)
Interest on Multi-currency medium term notes	(11,294,127)	(9,347,708)
Unwinding of discount on decommissioning provisions (Note 19)	(1,521,272)	(2,555,586)
Unwinding of discount on Notes (Note 18)	(20,049,522)	(22,450,169)
	(49,261,437)	(53,834,112)

Thai Petroleum royalties and remuneration paid

Under the terms of the Thai I regime, the concessionaire is required to pay production royalties to the Royal Thai Government computed based on 12.5% of value of petroleum sold for payment in cash and in kind respectively.

Under the Thai III regime, the concessionaire is required to pay production royalties to the Royal Thai Government computed based on sliding scale rates from 5.0% to 15.0% of the value of petroleum sold or disposed during the month, depending on the number of barrels sold or disposed during the month.

Special remuneration benefit ("SRB") is tax payable only in years concessionaire has petroleum profit. In calculating such profit (or loss), capital expenditure, operating costs and a special reduction of 35.0% operating expenses for the year and petroleum loss carried forward indefinitely from prior years may be deducted. SRB is calculated by exploration block on income per meter of well, subject to a ceiling of 75.0% of petroleum profit

Loss per share

Basic loss per share are calculated by dividing loss for the year attributable to owners of the Company by the weighted average number of ordinary shares outstanding during the financial year.

Diluted loss per share are calculated by dividing loss for the year attributable to owners of the Company by the weighted average number of ordinary shares outstanding during the financial year plus the weighted average number of ordinary shares that would be issued on the vesting of all performance shares under the Performance Share Plan (Note 21).

The following tables reflect the profit and share data used in the computation of basic and diluted loss per share for the years ended 31 December:

	GROUP	
	2018 US$	**2017** US$
Loss for the year attributable to owners of the Company used in the computation of basic and diluted loss per share	(137,352,425)	(139,235,546)
	No. of shares	No. of shares
Weighted average number of ordinary shares for basic loss per share computation	1,502,849,065	1,499,749,865
Effects of dilution		
Vesting of performance shares	5,186,848	9,098,533
Weighted average number of ordinary shares for diluted loss per share computation	1,508,035,913	1,508,848,398

In January 2017, the Company issued 1,255,183,632 detachable warrants pursuant to the Zero Coupon Notes (Note 18). The warrants were not included in calculating diluted loss per share because they are anti-dilutive.

07 Taxation

The major components of tax expense for the years ended 31 December 2018 and 2017 are:

	GROUP	
	2018 US$	**2017** US$
Current tax		
Current tax charge	5,065,116	5,944,867
Under provision in respect of previous years	616,217	26,253
	5,681,333	5,971,120
Deferred tax		
Reversal of temporary differences	(1,492,034)	(1,567,897)
Tax expense recognised in profit or loss	4,189,299	4,403,223

Relationship between tax expense and accounting loss

A reconciliation between tax expense and the accounting loss multiplied by the applicable tax rate for the years ended 31 December 2018 and 2017 is as follows:

	GROUP	
	2018 US$	**2017** US$
Loss before tax	(133,163,126)	(134,832,323)
Tax at domestic rates applicable in the countries where the Group operates	(29,483,912)	(37,146,614)
Adjustments		
Non-deductible expenses	38,928,932	33,620,797
Income not subject to tax	(15,335,192)	(2,480,239)
Effect of previously unrecognised and unused tax losses	(3,784,854)	(5,736,101)
Deferred tax assets not recognised	13,248,108	16,119,127
Underprovision in respect of previous years	616,217	26,253
Tax expense recognised in profit or loss	4,189,299	4,403,223

The above reconciliation is prepared by aggregating separate reconciliation for each national jurisdiction.

Pursuant to the tax rules and regulations in Singapore, Thailand, Indonesia, Vietnam and Cambodia, the subsidiaries located in the aforementioned countries are liable to taxes ranging from 17.0% to 50.0%, on the assessable profits generated in these countries.

For operations in Bangladesh, the tax liability is met from the sharing of oil under the terms of the PSC and no provision of current tax or deferred tax is required.

Deferred tax

Deferred tax liabilities at 31 December relate to the following:

	GROUP
	US$
Fair value adjustment on acquired reserves	
At 1 January 2017	38,404,491
Credit to profit or loss for the year	(1,567,897)
At 31 December 2017	36,836,594
Credit to profit or loss for the year	(1,492,034)
At 31 December 2018	35,344,560

Deferred tax assets have not been recognised in respect of these temporary differences and tax losses as they may not be used to offset taxable profits elsewhere in the Group, they have arisen in subsidiaries that have been loss-making for some time, and there are no other tax planning opportunities or other evidence of recoverability in the near future. The use of these tax losses is subject to the agreement of the tax authorities and compliance with certain provisions of the tax legislation of the respective countries in which the companies operate. The tax losses have an expiry period of 10 years.

Temporary differences arising in connection with interests in subsidiaries are insignificant.

The following deferred tax assets have not been recognised for the years ended 31 December:

	GROUP	
	2018 US$	**2017** US$
Differences in depreciation, depletion and amortisation for tax purposes	80,132,272	75,619,537
Unutilised tax losses	221,275,149	195,714,756
	301,407,421	271,334,293

The Group offsets tax assets and liabilities if and only if it has a legally enforceable right to set off current tax assets and current tax liabilities and the deferred tax assets and deferred tax liabilities relate to income taxes levied by the same tax authority.

08 Exploration and evaluation assets

	GROUP
	US$
Cost	
At 1 January 2017	585,859,110
Additions	37,758,376
Farm-out of working interest	(43,508,857)
At 31 December 2017	580,108,629
Additions	22,284,978
Dry hole expenses (Note 6)	(6,798,944)
Transfer to oil and gas properties (Note 9)	(27,183,197)
At 31 December 2018	568,411,466
Accumulated impairment	
At 1 January 2017	78,439,923
Impairment losses (Note 11)	120,720,863
At 31 December 2017	199,160,786
Impairment losses (Note 11)	61,358,426
At 31 December 2018	260,519,212
Net book value	
At 31 December 2018	307,892,254
At 31 December 2017	380,947,843

09 Oil and gas properties

	GROUP
	US$
Cost	
At 1 January 2017	644,394,548
Additions	18,436,124
At 31 December 2017	662,830,672
Additions	49,523,634
Dry hole expenses (Note 6)	(4,651,580)
Disposal of a subsidiary (Note 4)	(96,592,773)
Transfer from exploration and evaluation assets (Note 8)	27,183,197
At 31 December 2018	638,293,150
Accumulated depreciation, depletion and amortisation	
At 1 January 2017	306,451,860
Charge for the year	48,313,868
At 31 December 2017	354,765,728
Charge for the year	49,808,916
Disposal of a subsidiary (Note 4)	(79,521,924)
At 31 December 2018	325,052,720
Accumulated impairment	
At 1 January 2017 and 31 December 2017	130,524,058
Impairment losses (Note 11)	18,946,687
At 31 December 2018	149,470,745
Net book value	
At 31 December 2018	163,769,685
At 31 December 2017	177,540,886

10 Other property, plant and equipment

	RENOVATION	FURNITURE AND FITTINGS	OFFICE EQUIPMENT	COMPUTERS	REFURBISH-MENT ASSETS	GROUP TOTAL
	US$	US$	US$	US$	US$	US$
Cost						
At 1 January 2017	1,226,359	177,796	305,970	1,439,550	10,740,829	13,890,504
Additions	–	3,613	–	29,579	380,444	413,636
Disposals	–	–	–	(6,519)	–	(6,519)
Exchange differences	49,743	2,050	941	58,793	–	111,527
At 31 December 2017	1,276,102	183,459	306,911	1,521,403	11,121,273	14,409,148
Additions	–	737	179	27,203	2,349,625	2,377,744
Disposals	–	–	–	(32,442)	–	(32,442)
Exchange differences	(18,523)	(800)	(351)	(23,134)	–	(42,808)
At 31 December 2018	1,257,579	183,396	306,739	1,493,030	13,470,898	16,711,642
Accumulated depreciation						
At 1 January 2017	1,146,824	148,471	202,668	1,374,033	–	2,871,996
Charge for the year	72,031	26,720	80,918	70,836	–	250,505
Disposals	–	–	–	(5,604)	–	(5,604)
Exchange differences	49,743	1,944	942	57,818	–	110,447
At 31 December 2017	1,268,598	177,135	284,528	1,497,083	–	3,227,344
Charge for the year	7,502	4,531	22,404	24,064	–	58,501
Disposals	–	–	–	(32,442)	–	(32,442)
Exchange differences	(18,521)	(761)	(352)	(22,902)	–	(42,536)
At 31 December 2018	1,257,579	180,905	306,580	1,465,803	–	3,210,867
Net carrying amount						
At 31 December 2018	–	2,491	159	27,227	13,470,898	13,500,775
At 31 December 2017	7,504	6,324	22,383	24,320	11,121,273	11,181,804

11 Intangible assets

	GOODWILL	OTHERS	GROUP TOTAL
	US$	US$	US$
Cost			
At 1 January 2017, 31 December 2017 and 31 December 2018	106,039,993	1,669,721	107,709,714
Accumulated amortisation			
At 1 January 2017, 31 December 2017 and 31 December 2018	–	316,724	316,724
Accumulated impairment loss			
At 1 January 2017, 31 December 2017 and 31 December 2018	97,595,101	1,352,997	98,948,098
Net carrying amount			
At 31 December 2018	8,444,892	–	8,444,892
At 31 December 2017	8,444,892	–	8,444,892

Goodwill

Goodwill arises principally because of the following factors:

- The going concern value implicit in our ability to sustain and/or grow our business by increasing reserves and resources through new discoveries
- The ability to capture unique synergies that can be realised from managing a portfolio of both acquired and existing assets

Allocation of goodwill

For the purpose of impairment assessment, goodwill acquired through business combinations have been allocated as follows:

	GROUP	
	2018 US$	**2017** US$
Goodwill		
Bulu PSC	7,144,606	7,144,606
Cambodia Block A PA	1,300,286	1,300,286
	8,444,892	8,444,892

Impairment testing

Impairment losses on exploration and evaluation assets, oil and gas properties and intangible assets have been recognised as follows:

	GROUP	
	2018 US$	**2017** US$
Exploration and evaluation assets (Note 8)	61,358,426	120,720,863
Oil and gas properties (Note 9)	18,946,687	–
	80,305,113	120,720,863

During the year ended 31 December 2018, impairment losses on exploration and evaluation assets of US$61.4 million was recognised in relation to certain exploration assets of which the right to explore in these areas have expired or are near expiry, and the Group has no intention to extend the exploration period. Impairment losses on oil and gas properties of US$18.9 million was also recognised to write down the CGU's carrying amount to its recoverable amount. The recoverable amount of each CGU is determined based on a value-in-use calculation.

In 2017, an impairment loss on exploration and evaluation assets of US$120.7 million was recognised as the Group has decided to cease participation in the asset.

The calculation of value-in-use of the oil exploration and production CGU is most sensitive to the following assumptions:

- Production volumes
- Discount rates
- Crude oil prices

Estimated production volumes are based on detailed data for the assets and take into account development plans for the assets agreed by management as part of the long-term planning process.

As at 31 December 2018 and 2017, no impairment charge was required for goodwill arising from the acquisition of exploration and evaluation assets, with any reasonably possible change to the key assumptions applied not likely to cause the recoverable value to be below their carrying amounts.

The Group generally estimates value-in-use for the oil exploration and production CGU using a discounted cash flow model. The future cash flows are discounted to their present value using a pre-tax discount rate of 8.0% to 10.0% (2017: 8.0% to 10.0%) that reflects current market assessments of the time value of money and the risks specific to the asset. The discount rate is derived from the Group's weighted average cost of capital ("WACC"), with appropriate adjustments made to reflect the risks specific to the CGU.

Oil prices are based on average forecast for Brent Crude future prices and adjusted for quality, transportation fees and regional price differences. The Group's calculation incorporates a range of oil prices from US$60 to US$80 (2017: US$60 to US$80) per barrel.

12 Investment in subsidiaries

	COMPANY	
	2018 US$	**2017** US$
Unquoted shares, at cost	326,809,883	326,809,783
Capital contribution for share-based payments	9,934,543	8,762,753
	336,744,426	335,572,536

Significant subsidiaries of the Group

Details of the Group's significant subsidiaries at 31 December are as follows:

NAME OF ENTITIES	PRINCIPAL ACTIVITIES	COUNTRY OF INCORPORATION	% OF EQUITY INTEREST	
			2018	2017
KrisEnergy (Asia) Ltd.	Investment holding	British Virgin Islands	100	100
KrisEnergy Pte. Ltd.	Provision of management support service	Singapore	100	100
KrisEnergy (Gulf of Thailand) Ltd.[1,2]	Investment holding	Cayman Islands	100	100
KrisEnergy (Cambodia) Ltd	Exploration and production of oil and gas	Cambodia	100	100
KrisEnergy (Phu Khanh 120) Ltd.[1,2]	Exploration and production of oil and gas	British Virgin Islands	100	100
KrisEnergy (Vietnam 115) Ltd[1,2]	Exploration and production of oil and gas	British Virgin Islands	100	100
KrisEnergy East Seruway B.V.[1,2]	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy (Satria) Ltd[1,2]	Exploration and production of oil and gas	British Virgin Islands	100	100
KrisEnergy (Sakti) B.V.[1,2]	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy (Bala-Balakang) B.V.[1,2]	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy (Udan Emas) B.V.[1,2]	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy Bangladesh Limited[1,2]	Exploration and production of oil and gas	Jersey	100	100
KrisEnergy (Apsara) Ltd.[1,2]	Exploration and production of oil and gas	Bermuda	100	100
KrisEnergy G10 (Thailand) Ltd.	Exploration and production of oil and gas	Thailand	100	100
KrisEnergy (Block A Aceh) B.V.[1,2]	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy Marine B.V.	Charter and sub-charter of Mobile Offshore Production Unit	The Netherlands	100	100
SJ Production Barge Ltd[3]	Investment holding	British Virgin Islands	100	100
KrisEnergy (East Muriah) Limited	Exploration and production of oil and gas	British Virgin Islands	100	100
KrisEnergy Kutai B.V.	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy Kutei B.V.	Exploration and production of oil and gas	The Netherlands	100	100
KrisEnergy (Song Hong 105) Ltd[1,2]	Exploration and production of oil and gas	British Virgin Islands	100	100
KrisEnergy (Andaman II) Ltd.[4]	Exploration and production of oil and gas	British Virgin Islands	100	–

NOTES

1 Capital stock in this entity pledged as collateral for Revolving Credit Facility (Note 18)
2 Capital stock in this entity pledged as junior ranking security under the Zero Coupon Notes (Note 18)
3 Capital stock in this entity pledged as first ranking security under the Zero Coupon Notes (Note 18)
4 Entity was incorporated on 13 February 2018.

Details of composition of the Group

Information about the composition of the Group at the end of the financial year is as follows:

COUNTRY OF INCORPORATION	PRINCIPAL ACTIVITIES	NUMBER OF WHOLLY-OWNED SUBSIDIARIES	
		2018	2017
Bermuda	Exploration and production of oil and gas	1	1
British Virgin Island	Exploration and production of oil and gas	6	5
British Virgin Island	Investment holding	9	8
British Virgin Island	Provision of offshore management support service	1	1
Cambodia	Exploration and production of oil and gas	2	1
Cayman Islands	Exploration and production of oil and gas	1	1
Cayman Islands	Investment holding	0	1
Jersey	Exploration and production of oil and gas	1	1
Singapore	Investment holding	2	2
Singapore	Provision of management support service	1	1
Thailand	Exploration and production of oil and gas	3	3
The Netherlands	Charter and sub-charter of Mobile Offshore Production Unit	1	1
The Netherlands	Exploration and production of oil and gas	12	12
The Netherlands	Investment holding	2	2
		42	40

13 Inventories

	GROUP	
	2018 US$	2017 US$
Balance sheet		
Drilling supplies and materials	8,217,033	10,201,243
Crude oil	13,713,191	12,367,796
	21,930,224	22,569,039
Profit or loss		
Inventories recognised as an expense in cost of sales	103,051,424	99,779,055
Inclusive of the following charge		
Inventories written down (Note 6)	8,940,159	2,421,983

14 Trade and other receivables

	GROUP		COMPANY	
	2018 US$	2017 US$	2018 US$	2017 US$
Trade and other receivables (current)				
Trade receivables	5,471,558	8,981,261	–	–
Refundable deposits	773,767	323,158	–	–
Other receivables	26,512,115	39,273,651	–	–
Joint operation receivables	5,193,428	11,285,092	–	–
	37,950,868	59,863,162	–	–
Other receivables (non-current)				
Other receivables	4,088,466	4,421,956	–	–
Amounts due from subsidiaries	–	–	718,457,001	729,357,386
Loss allowance	–	–	(508,938,056)	–
Total trade and other receivables (current and non-current)	42,039,334	64,285,118	209,518,945	729,357,386
Cash and bank balances (Note 15)	77,606,440	73,824,848	274,059	247,417
Value added tax receivables	(16,727,532)	(25,725,863)	–	–
Total financial assets carried at amortised cost	102,918,242	112,384,103	209,793,004	729,604,803

Other receivables (current)

	GROUP		COMPANY	
	2018 US$	2017 US$	2018 US$	2017 US$
Payment on behalf of joint operation's partners	5,851,368	6,168,802	–	–
Proportionate share of joint operation's other receivables	7,964,013	11,501,511	–	–
Value added tax receivables	12,639,066	21,303,907	–	–
Others	57,668	299,431	–	–
	26,512,115	39,273,651	–	–

Trade receivables are non-interest bearing and are generally on 30-day terms. They are recognised at their original invoice amounts which represent their fair values on initial recognition.

For the purpose of impairment assessment, the trade and other receivables are considered to have low credit risk as there has been no significant increase in the risk of default on the receivables since initial recognition. Accordingly, for the purpose of impairment assessment for these receivables, the loss allowance is measured at an amount equal to 12-month ECL.

In determining the ECL, management has taken into account the historical default experience and the financial position of the counterparties, adjusted for factors that are specific to the debtors and general economic conditions of the industry in which the debtors operate, in estimating the probability of default of each of these financial assets occurring within their respective loss assessment time horizon, as well as the loss upon default in each case. The Group has performed a risk profile of trade receivables based on the Group's credit risk grading framework, and has determined that the trade receivables are subject to immaterial credit loss.

There has been no change in the estimation techniques or significant assumptions made during the current reporting period in assessing the loss allowance for trade and other receivables.

Joint operation receivables and other receivables relate to amounts due from the joint operators for cash calls and expenses incurred on their behalf in excess of the Group's obligation. These amounts are unsecured, non-interest bearing, and will be settled by future cash calls within the next 12 months. The Group has determined that the other receivables are subject to immaterial credit loss.

Amounts due from subsidiaries are non-trade related, unsecured, non-interest bearing, and repayable upon demand. Amounts due from subsidiaries have been classified as non-current assets as the Company does not expect for repayment within 12 months after the reporting date. As at 31 December 2018, the Company has recognised a loss allowance of US$508.9 million (2017:US$Nil) for amounts due from subsidiaries as these subsidiaries continued to make losses during the year.

Trade and other receivables denominated in foreign currencies at 31 December are as follows:

	GROUP	
	2018 US$	**2017** US$
Thai Baht	132,911	210,709

At reporting date, the Group has value added tax receivables with a nominal amount of US$16.7 million (2017: US$25.7 million). For the year ended 31 December 2018, US$0.4 million (2017: US$4.0 million) of value added tax receivables was written off as the claims may not be recoverable due to the Group's decision to cease participation in the assets.

15 Cash and bank balances

	GROUP		COMPANY	
	2018 US$	**2017** US$	**2018** US$	**2017** US$
Cash at banks and on hand	69,336,440	65,554,848	274,059	247,417
Short-term deposits	8,270,000	8,270,000	–	–
Cash and bank balances	77,606,440	73,824,848	274,059	247,417

Short-term deposits earn interests at the respective short-term deposit rates. The weighted average effective interest rate as at 31 December 2018 for the Group was 1.1% (2017: 0.4%).

For the purpose of the consolidated statement of cash flows, cash and cash equivalents comprise the following at 31 December:

	GROUP	
	2018 US$	**2017** US$
Cash and bank balances	77,606,440	73,824,848
Less: restricted cash	(8,270,000)	(8,270,000)
Cash and cash equivalents	69,336,440	65,554,848

As at 31 December 2018, the amounts held under joint operations amounted to US$36.7 million (2017:US$37.7 million).

Cash at banks and on hand denominated in foreign currencies at 31 December are as follows:

	GROUP	
	2018 US$	**2017** US$
Thai Baht	347,695	1,528,065
Singapore Dollar	214,014	212,400
United States Dollar	330,928	172,424

16 Share capital and reserve

Share capital

	GROUP AND COMPANY			
		2018		**2017**
	No. of shares	US$	No. of shares	US$
Issued and fully paid ordinary shares				
At 1 January	1,502,849,065	1,878,562	1,499,622,024	1,874,528
Warrants exercised on 17 February 2017	–	–	9,000	11
Warrants exercised on 7 March 2017	–	–	2,376	3
Vesting of equity-settled share transactions with employees on 19 July 2017	–	–	205,154	257
Vesting of equity-settled share transactions with employees on 29 December 2017	–	–	3,010,511	3,763
At 31 December	1,502,849,065	1,878,562	1,502,849,065	1,878,562

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. All ordinary shares carry one vote per share without restrictions. The ordinary shares have a par value of US$0.00125 (2016: US$0.00125) each.

Share premium

	GROUP AND COMPANY	
	2018	**2017**
	US$	US$
At 1 January	730,302,151	729,529,098
Warrants exercised on 17 February 2017	–	978
Warrants exercised on 7 March 2017	–	260
Vesting of equity-settled share transactions with employees on 19 July 2017	–	62,888
Vesting of equity-settled share transactions with employees on 29 December 2017	–	708,927
At 31 December	730,302,151	730,302,151

Foreign currency translation reserve

The foreign currency translation reserve represents exchange differences arising from the translation of the financial statements of foreign subsidiaries whose functional currencies are different from that of the Group's presentation currency.

Employee share option reserve

Employee share option reserve represents equity-settled share transactions granted to employees. The reserve is made up of the cumulative value of services received from employees recorded over the vesting period commencing from the grant date of equity-settled share transactions, and is reduced by the expiry or exercise of the share transactions.

General reserve

General reserve represents the change in ownership of subsidiary arising from disposal of interest in subsidiary and fair value of the 1,255,183,632 detachable warrants issued pursuant to the Zero Coupon Notes (Note 18). As at 31 December 2018 and 31 December 2017, the outstanding warrants were 1,255,172,256.

17 Trade and other payables

	GROUP		COMPANY	
	2018 US$	2017 US$	2018 US$	2017 US$
Trade and other payables (current)				
Trade payables	16,156,474	11,694,663	128,037	13,787
Joint operation payables	1,169,178	1,664,675	–	–
Staff payroll and bonus payables	329,760	322,360	–	–
Other payables	55,889,854	30,518,032	10,934,794	5,909,758
	73,545,266	44,199,730	11,062,831	5,923,545
Other payables (non-current)				
Amounts due to subsidiaries	–	–	25,628,394	25,711,246
Total trade and other payables (current and non-current)	73,545,266	44,199,730	36,691,225	31,634,791
Accrued operating expenses	21,935,797	19,486,897	1,877,024	1,039,990
Loans and borrowings (Note 18)	459,072,439	424,612,597	290,802,439	276,342,597
Amount from offtakers for crude sales	(23,300,089)	(18,990,117)	–	–
Value added tax payables	–	(1,763,616)	–	–
Total financial liabilities carried at amortised cost	531,253,413	467,545,491	329,370,688	309,017,378

Trade payables are non-interest bearing and are normally settled on 60-day terms.

Joint operation payables are cash calls due to the operator of joint operations. These amounts are unsecured, non-interest bearing, and are to be settled in cash.

Other payables (current)

	GROUP		COMPANY	
	2018 US$	2017 US$	2018 US$	2017 US$
Payment on behalf by joint operation's partners	4,190,198	52,935	–	–
Proportionate share of joint operation's other payables	7,774,520	3,712,816	–	–
Accrued interest payable for Multi-currency medium term notes	10,908,701	5,879,642	10,908,701	5,879,642
Amount from offtakers for crude sales	23,300,089	18,990,117	–	–
Value added tax payables	–	1,763,616	–	–
Others	9,716,346	118,906	26,093	30,116
	55,889,854	30,518,032	10,934,794	5,909,758

Included in accrued operating expenses is the Group's proportionate share of joint operation's accrued expenses amounting to US$8.3 million (2017: US$12.6 million).

Amounts due to subsidiaries are unsecured, non-interest bearing and repayable on demand. Amounts due to subsidiaries have been classified as non-current liabilities as the Company does not expect to repay within 12 months after the reporting date.

Trade and other payables denominated in foreign currencies at 31 December are as follows:

	GROUP	
	2018 US$	2017 US$
Thai Baht	190,054	1,930,795

18 Loans and borrowings

	Maturity	GROUP 2018 US$	GROUP 2017 US$	COMPANY 2018 US$	COMPANY 2017 US$
Current					
Revolving Credit Facility	2018/2019	20,000,000	148,270,000	–	–
		20,000,000	148,270,000	–	–
Non-current					
Revolving Credit Facility	2020	148,270,000	–	–	–
Multi-currency medium term notes	2022/2023	189,674,942	179,155,878	189,674,942	179,155,878
Unsecured term loans	2022	34,417,937	34,417,937	34,417,937	34,417,937
Zero Coupon Notes	2024	66,709,560	62,768,782	66,709,560	62,768,782
		439,072,439	276,342,597	290,802,439	276,342,597
		459,072,439	424,612,597	290,802,439	276,342,597

Multi-currency medium term notes

The S$130.0 million senior unsecured notes due 2022 ("2022 Notes") and S$200.0 million senior unsecured notes due 2023 ("2023 Notes") have a fixed rate coupon of 4% payable annually, 2% payable annually in cash and 2% payable annually in cash or accrued at the discretion of the Company. The fixed rate coupon of 4% will be payable in the form of cash from the fifth coupon payment. In addition to the cash coupon, an additional cash coupon per interest period will be paid subject to the Brent crude oil benchmark, giving rise to embedded derivatives (Note 22).

As at 31 December 2018, the fair value of the 2022 Notes and 2023 Notes was US$102.9 million (2017: US$130.5 million).

Revolving Credit Facility

The Revolving Credit Facility ("RCF") with DBS Bank Ltd. ("DBS"), which was due to mature on 30 June 2018, has a total commitment of US$148.3 million and pursuant to the RCF, DBS has waived all financial covenants since November 2016.

On 29 March 2018, the Borrower and DBS signed an extension agreement where the RCF was extended by two-years to 30 June 2020, with no change to terms of the RCF.

On 9 April 2018, DBS provided an additional commitment of US$20.0 million (the "Bridge Upsize") for a period of up to three months. On 5 July 2018, the Bridge Upsize maturity date was extended for three months to 8 October 2018, and on 5 October 2018, the Bridge Upsize maturity date was extended for three months to 8 January 2019. On 8 January 2019, the Bridge Upsize maturity date was extended for one month to 8 February 2019, and on 1 February 2019, the Bridge Upsize maturity date was extended for one month to 8 March 2019. On 5 March 2019, the Bridge Upsize maturity date was extended for one month to 8 April 2019.

The Guarantors of the RCF are the Company, KrisEnergy Holding Company Ltd., KrisEnergy Management Ltd., KrisEnergy International (Thailand) Holdings Ltd., KrisEnergy (Gulf of Thailand) Ltd., KrisEnergy Netherlands Holdings Pte Ltd., KrisEnergy Asia Coöperatief U.A., KrisEnergy Asia Holdings B.V., KrisEnergy (Block A Aceh) B.V., KrisEnergy (Satria) Ltd., KrisEnergy Bangladesh Limited, KrisEnergy (Apsara) Ltd. and KrisEnergy (Cambodia) Holding Ltd.

Please refer to Note 12 for subsidiaries that provide the above collaterals.

Unsecured term loans

The interest rate of the unsecured term loans is LIBOR plus margin of 4.0% per annum, with principal repayment based on a percentage of the aggregate amount of the loan outstanding from August 2019 to February 2022.

Zero Coupon Notes

In 2017, the Company issued and received gross proceeds of S$139.5 million (US$96.4 million) in principal amount of senior secured Zero Coupon Notes due 2024 (the "Zero Coupon Notes") and 1,255,183,632 detachable warrants to its shareholders. Each warrant converts to one share in the ordinary share capital of the Company at the exercise price of S$0.110 per share.

As at 31 December 2018, the carrying value of the Zero Coupon Notes and warrants (Note 16) were US$66.7 million (2017: US$62.8 million) and US$40.3 million (2017: US$40.3 million) respectively. As at 31 December 2018, the fair value of the Zero Coupon Notes were US$58.4 million (2017: US$60.0 million).

Reconciliation of liabilities arising from financing activities

The table below details changes in the Group's liabilities arising from financing activities, including both cash and non-cash changes. Liabilities arising from financing activities are those for which cash flows were, or future cash flows will be, classified in the Group's consolidated statement of cash flows as cash flows from financing activities.

	REVOLVING CREDIT FACILITY	UNSECURED TERM LOAN	MULTICURRENCY MEDIUM TERM NOTE	ZERO-COUPON NOTE	DERIVATIVE LIABILITIES	GROUP TOTAL
	US$	US$	US$	US$	US$	US$
At 1 January 2017	188,270,000	–	228,692,762	–	37,974,078	454,936,840
Financing cash flows[1]	(40,000,000)	–	–	94,404,115	–	54,404,115
Non-cash changes						
Equity component of Notes	–	–	–	(40,300,701)	–	(40,300,701)
De-recognition of cross currency swaps	–	–	35,175,946	–	(37,974,078)	(2,798,132)
Settlement for early termination of hedge	–	34,417,937	–	–	–	34,417,937
Fair value adjustments	–	–	(78,731,387)	–	7,013,828	(71,717,559)
Accretion of discount	–	–	17,978,065	4,472,104	–	22,450,169
Foreign exchange movement	–	–	(23,959,508)	4,193,264	307,640	(19,458,604)
At 31 December 2017	148,270,000	34,417,937	179,155,878	62,768,782	7,321,468	431,934,065
Financing cash flows[1]	20,000,000	–	–	–	–	20,000,000
Non-cash changes						
Fair value adjustments	–	–	–	–	(4,079,847)	(4,079,847)
Accretion of discount	–	–	14,658,731	5,390,791	–	20,049,522
Foreign exchange movement	–	–	(4,139,667)	(1,450,013)	(274,880)	(5,864,560)
At 31 December 2018	168,270,000	34,417,937	189,674,942	66,709,560	2,966,741	462,039,180

NOTE

1 The cash flows make up the net amount of proceeds from borrowings and repayments of borrowings in the consolidated statement of cash flows.

19 Provisions

	GROUP
	US$
Decommissioning provisions	
At 1 January 2017	50,406,946
Arising during the year	37,392
Write-back of unused provisions	(7,892,881)
Utilisation	(2,431,897)
Unwinding of discount	2,555,586
At 31 December 2017	42,675,146
Arising during the year	18,802,472
Disposal of a subsidiary (Note 4)	(7,813,570)
Write-back of unused provisions	(29,006,833)
Utilisation	(3,971,874)
Unwinding of discount	1,521,272
At 31 December 2018	22,206,613

The Group provides for the future cost of decommissioning oil production facilities and pipelines on a discounted basis on the installation of those facilities.

The average discount rate used in the calculation of the provisions as at 31 December 2018 is 10.0% (2017: 10.0%).

20 Employee benefit liability

The Group has defined benefit pension plans for its employees in Indonesia and Thailand. The plans are governed by the local labour laws, and all local permanent employees are entitled to the plan. Salary is a basis of payment for severance and service benefits which consist of basis salary plus fixed allowances.

The amount included in the consolidated statement of financial position arising from the Group's obligation in respect of its defined benefit pension plans are as follows:

	GROUP	
	2018 US$	**2017** US$
Present value of defined benefit obligations	792,925	1,581,491
Re-measurement of defined benefit obligations	(181,290)	49,321
Net liability arising from defined benefit obligations	611,635	1,630,812

Changes in present value of the defined benefit obligations are as follows:

	GROUP US$
At 1 January 2017	1,410,770
Interest cost	87,061
Current service cost	1,490,589
Re-measurement (gains) losses	
Re-measurement of other long term employee benefits	579
Actuarial gains and losses arising from changes in financial assumption	81,410
Actuarial gains and losses arising from experience adjustments	(32,089)
Benefits paid	(1,407,508)
At 31 December 2017	1,630,812
Interest cost	91,742
Current service cost	274,022
Curtailments	(919,017)
Re-measurement (gains) losses	
Re-measurement of other long term employee benefits	(2,456)
Actuarial gains and losses arising from changes in financial assumption	(81,518)
Actuarial gains and losses arising from experience adjustments	(99,772)
Benefits paid	(282,178)
At 31 December 2018	611,635

The cost of the defined benefit pension plans and the present value of the defined benefit obligations are determined using actuarial valuations. The actuarial valuation involves making various assumptions. The principal assumptions used in determining defined benefit obligations are shown below:

	2018	**2017**
Retirement age	55 to 65 years	55 to 58 years
Discount rate	2.5% to 8.5% per annum	3% to 7% per annum
Long-term salary increase	5% per annum	5% per annum
Voluntary resignation	6% for employee before the age of 30 and linear decrease until 0% at the age of 58	6% for employee before the age of 30 and linear decrease until 0% at the age of 56

The sensitivity analysis below has been determined based on reasonably possible changes of each significant assumption on the defined benefit obligations as of the end of the reporting period, assuming if all other assumptions were held constant:

		2018 US$	**2017** US$
Discount rate	+ 50 basis points	(17,131)	(48,959)
	- 50 basis points	18,852	55,262

21 Share-based payments

The expenses recognised for employee services received during the year are shown in the following table:

	GROUP	
	2018 US$	**2017** US$
Expense arising from cash-settled share-based payment transactions	667,488	(57,999)
Expense arising from equity-settled share-based payment transactions	245,016	531,161
	912,504	473,162

Virtual Shares Award ("VSA")

This VSA is a performance based share incentive scheme to reward eligible employees for their continued contribution to KrisEnergy and to serve as a long-term incentive reward to motivate and retain eligible employees, with a view to align the interests of such employees with the interests of KrisEnergy and its shareholders.

The virtual share represents a cash award which is linked to KrisEnergy's share price. No shares are actually issued or transferred to the employee who has been awarded virtual shares. The cash amount depends on KrisEnergy's closing share price on the relevant vesting date and is calculated based on the number of virtual shares vested on the relevant vesting date multiplied by the vesting share price.

On 19 July 2017 and 29 December 2017, 42,269 and 670,855 virtual shares vested at vesting share price of S$0.148 and S$0.101 respectively.

As at 31 December 2018 and 2017, there were no virtual shares granted and not vested.

Performance Share Plan ("PSP")

The PSP is a performance based share incentive scheme to reward selected employees and directors of the Company, who have contributed to the growth and performance of the Group and for their continued support and loyalty, with a direct interest in KrisEnergy.

The shares will be awarded to the selected employees if they remain employed by KrisEnergy with a clean employment record during the relevant vesting period. When the shares are fully vested, the shares will be issued and allotted to an account or sub-account with the Central Depository (Pte) Limited ("CDP") in Singapore within ten (10) business days of the vesting date.

On 19 July 2017 and 29 December 2017, 205,154 and 3,010,511 performance shares vested and ordinary shares were issued (Note 16).

As at 31 December 2018, the employee share option reserve for the PSP amounts to US$1.0 million (2017: US$0.8 million).

There has been no cancellation or modification to the employee share-based payments during the year ended 2018 and 2017.

The fair value of the VSA and PSP are estimated at reporting date and grant date respectively, using a Monte Carlo simulation model, taking into account the terms and conditions upon which the shares were granted. The model simulates a sophisticated random number generator of random variables based on their historical distributions. These variables are then input into a model predicting the price behaviors of the instruments, and the mean of this distribution is taken as the approximate fair value. The valuations are split into three tranches based on the vesting dates.

The following table lists the inputs to the Monte Carlo simulation models for the VSA and PSP respectively. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the share-based payments is indicative of future trends, which may not necessarily be the actual outcome.

	2018	**2017**
VSA		
Risk free rate (%)	–	0.8% to 1.2%
Expected volatility (%)	–	40% to 60%
Annual employee exit rate (%)	–	1% to 17%
PSP		
Risk free rate (%)	0.9% to 1.4%	0.9% to 1.4%
Expected volatility (%)	35% to 48%	35% to 48%
Annual employee exit rate (%)	1% to 3%	1% to 3%

Management Shareholders Awards ("MS-Awards")

As disclosed and further described in the Prospectus dated 12 July 2013, under the MS-Awards granted pursuant to the KrisEnergy PSP during the IPO, up to 3.0% (issued under equal First Tranche and Second Tranche) of the issued ordinary shares in the capital of the Company ("Shares") may be vested upon the satisfaction of the conditions of the MS-Awards.

Following the exit of First Reserve Fund, XII LP on 6 April 2018, the First Tranche Condition (as defined in the Prospectus had) been satisfied. However, in accordance with and as permitted under the terms of the MS-Awards, as the Company does not have sufficient distributable reserves or amounts credited to its premium account at such juncture to make the required issue of Shares (being the first one-third of the First Tranche), the Company has paid a cash sum equal to the aggregate fair market value of the Shares that would otherwise have been issued.

As at 31 December 2018, the carrying amount to the liability relating to the MS-Awards was US$0.7 million (2017: US$Nil).

22 Derivative liabilities

Embedded derivatives

The 2022 Notes and 2023 Notes have embedded derivatives arising from the additional cash coupon per interest period which will be paid subject to the Brent crude oil benchmark. If the Brent crude oil benchmark is greater than US$70 per barrel, the additional cash coupon will be 1% per annum, for each increase in Brent crude oil benchmark by US$10 per barrel above US$70 per barrel, up to a maximum of 3% per annum.

As at 31 December 2018, the carrying value of the embedded derivatives was US$3.0 million (2017: US$7.3 million). The net fair value gain on embedded derivatives of US$4.1 million (2017: loss of US$2.1 million) was recognised in other operating expenses (Note 6).

23 Commitments

Operating lease commitments

The Group has entered into non-cancellable commercial property leases for its office premises and bareboat charters for its operations. These operating leases have remaining lease terms of one year or more.

Future minimum lease payments payable under non-cancellable operating leases as at 31 December are as follows:

	GROUP	
	2018 US$	**2017** US$
Within one year	43,685,990	43,699,024
After one year but not more than five years	26,954,037	68,774,198
	70,640,027	112,473,222

Capital commitments

Certain of our joint operations have firm capital commitments where we are required to participate in minimum exploration activities. The Group's share of the estimated firm minimum exploration commitments is approximately US$40.1 million (2017: US$56.1 million).

At the reporting date, the Group's outstanding minimum exploration commitments will fall due as follows:

	GROUP	
	2018 US$	**2017** US$
Within one year	1,260,000	18,266,000
Within two to five years	38,840,000	37,880,000
	40,100,000	56,146,000

As at 31 December 2018, there are optional capital commitments of US$63.8 million (2017: US$38.5 million) for exploration activities and approximately US$33.1 million (2017: US$Nil) contractual commitments for development activities.

24 Related party disclosures

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year was as follows:

	GROUP	
	2018 US$	**2017** US$
Salaries and bonus	4,392,064	6,865,195
Central Provident Fund contributions	77,056	58,007
Share-based payments	259,290	538,779
	4,728,410	7,461,981
Comprising amounts paid to		
Directors of the Company	1,137,158	3,999,188
Other key management personnel	3,591,252	3,462,793
	4,728,410	7,461,981

25 Fair value of financial instruments

Assets and liabilities measured at fair value

Management considers that the carrying amounts of financial assets and financial liabilities recorded at amortised cost in the financial statements, other than loans and borrowings whose fair values are disclosed separately in Note 18, approximate their fair values due to the relatively short-term maturity of these financial instruments.

The following table shows an analysis of assets and liabilities measured at fair value at the end of the reporting period:

	GROUP AND COMPANY			
	LEVEL 1	LEVEL 2	LEVEL 3	TOTAL
	US$	US$	US$	US$
2018				
Financial liabilities at fair value through profit or loss				
Derivative liabilities (Note 22)				
Embedded derivatives	–	2,966,741	–	2,966,741
2017				
Financial liabilities at fair value through profit or loss				
Derivative liabilities (Note 22)				
Embedded derivatives	–	7,321,468	–	7,321,468

Level 2 fair value measurements

The following is a description of the valuation techniques and inputs used in the fair value measurement for assets that are categorised within Level 2 of the fair value hierarchy:

Embedded derivatives

Embedded derivatives are valued using the discounted cash flow method, under which, future contractual cash flows (i.e., Brent-linked additonal cash interest) are discounted to the valuation date. As the Brent-linked additional cash interest depends on future Brent prices, Monte-Carlo simulation method was adopted to project prospective Brent prices, which can be applied to compute the appropriate level of additional interest.

26 Financial risk management objectives and policies

The Group is exposed to financial risks arising from its operations and the use of financial instruments. The key financial risks include credit risk, interest rate risk, liquidity risk, commodity price risk and foreign currency risk. It is, and has been throughout the current financial year, the Group's policy that no derivatives shall be undertaken, except for the use as hedging instruments where appropriate and cost-efficient.

The following sections provide details regarding the Group's exposure to the above-mentioned financial risks and the objectives, policies and processes for the management of these risks.

Credit risk

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. The Group's exposure to credit risk arises primarily from trade and other receivables. For other financial assets (including cash and bank balances and derivatives), the Group minimises credit risk by dealing exclusively with high credit rating counterparties.

Exposure to credit risk

At the end of the reporting date, the Group's maximum exposure to credit risk is represented by the carrying amount of each class of financial assets recognised in the consolidated statement of financial position.

The Group develops and maintains the Group's credit risk gradings to categorise exposures according to their degree of risk of default. The credit rating information is supplied by independent rating agencies where available and, if not available, the Group uses other publicly available financial information and the trading records to rate its major customers and other debtors. The Group's exposure and the credit ratings of its counterparties are continuously monitored and the aggregate value of transactions concluded is spread amongst approved counterparties.

The Group's current credit risk grading framework comprises the following categories:

CATEGORY	DESCRIPTION	BASIS FOR RECOGNISING EXPECTED CREDIT LOSSES (ECL)
Performing	The counterparty has a low risk of default and does not have any past-due amounts.	12-month ECL
Doubtful	Amount is >90 days past due or there has been a significant increase in credit risk since initial recognition.	Lifetime ECL – not credit-impaired
In default	There is evidence indicating the asset is credit-impaired.	Lifetime ECL – credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Group has no realistic prospect of recovery.	Amount is written off

The table below details the credit quality of the Group's financial assets, as well as maximum exposure to credit risk by credit risk rating grades:

	NOTE	INTERNAL CREDIT RATING	12-MONTH OR LIFETIME ECL	GROSS CARRYING AMOUNT	LOSS ALLOWANCE	NET CARRYING AMOUNT
				US$	US$	US$
2018						
GROUP						
Trade and other receivables	14	Performing	12-month ECL	25,311,802	–	25,311,802
COMPANY						
Other receivables	14	Performing	12-month ECL	209,518,945	–	209,518,945
Other receivables	14	In default	Lifetime ECL	508,938,056	(508,938,056)	–

Credit risk concentration profile

At the reporting date, approximately 71.6% (2017: 89.6%) of the Group's receivables arises from the Group's working interest in G10/48 Concession, G11/48 Concession, G6/48 Concession, B9A and B8/32 Concessions, and Block 9 PSC.

Financial assets that are neither past due nor impaired

Trade and other receivables that are neither past due nor impaired are with creditworthy debtors with good payment record with the Group. Cash and cash equivalents are placed with or entered into with reputable financial institutions or companies with high credit ratings and no history of default.

Financial assets that are either past due or impaired

Information regarding financial assets that are either past due or impaired is disclosed in Note 14.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of the Group's financial instrument will fluctuate because of changes in market interest rates. The Group's exposure to interest rate risk arises primarily from their floating rate loans and borrowings, which are contractually re-priced at drawdown date.

Sensitivity analysis for interest rate risk

As at 31 December 2018, if LIBOR interest rates had been 50 basis points lower/higher with all other variables held constant, the Group's loss before tax would have been US$0.9 million (2017: US$0.9 million) lower/higher, arising mainly as a result of lower/higher interest expense on floating rate loans and borrowings (Note 18).

Liquidity risk

The Group and the Company maintain sufficient cash and cash equivalents to finance their activities. The Group minimises liquidity risk by keeping committed credit lines available.

Liquidity risk is the risk that the Group will encounter difficulty in meeting financial obligations due to shortage of funds. The Group's exposure to liquidity risk arises primarily from mismatches of the maturities of financial assets and liabilities.

Management's going concern assessment is disclosed in Note 1 to the financial statements.

The following tables detail the remaining contractual maturity for financial assets and financial liabilities. The tables have been drawn up on the undiscounted cash flows of financial assets and financial liabilities based on the earliest date on which the Group can be required to pay and the interest that will be earned on those assets. The table includes both interest and principal cash flows. The adjustment column represents the possible future cash flows attributable to the instrument included in the maturity analysis which is not included in the carrying amount of the financial assets and financial liabilities on the statement of financial position.

	WITHIN ONE YEAR	AFTER ONE BUT WITHIN FIVE YEARS	AFTER FIVE YEARS	ADJUSTMENTS	GROUP TOTAL
	US$	US$	US$	US$	US$
2018					
Financial assets					
Trade and other receivables	25,311,802	–	–	–	25,311,802
Cash and bank balances	77,606,440	–	–	–	77,606,440
	102,918,242	–	–	–	102,918,242
Financial liabilities					
Trade and other payables	(50,245,177)	–	–	–	(50,245,177)
Accrued operating expenses	(21,935,797)	–	–	–	(21,935,797)
Derivative liabilities	–	(2,966,741)	–	–	(2,966,741)
Loans and borrowings	(36,023,711)	(450,709,602)	(101,432,669)	129,093,543	(459,072,439)
	(108,204,685)	(453,676,343)	(101,432,669)	129,093,543	(534,220,154)
Total net	(5,286,443)	(453,676,343)	(101,432,669)	129,093,543	(431,301,912)

	WITHIN ONE YEAR	AFTER ONE BUT WITHIN FIVE YEARS	AFTER FIVE YEARS	ADJUSTMENTS	GROUP TOTAL
	US$	US$	US$	US$	US$
2017					
Financial assets					
Trade and other receivables	38,559,255	–	–	–	38,559,255
Cash and bank balances	73,824,848	–	–	–	73,824,848
	112,384,103	–	–	–	112,384,103
Financial liabilities					
Trade and other payables	(23,445,997)	–	–	–	(23,445,997)
Accrued operating expenses	(19,486,897)	–	–	–	(19,486,897)
Derivative liabilities	–	(7,321,468)	–	–	(7,321,468)
Loans and borrowings	(159,509,008)	(169,403,237)	(256,194,677)	160,494,325	(424,612,597)
	(202,441,902)	(176,724,705)	(256,194,677)	160,494,325	(474,866,959)
Total Net	(90,057,799)	(176,724,705)	(256,194,677)	160,494,325	(362,482,856)

Commodity price risk

The Group is exposed to the price volatility of crude oil. It generates revenue from selling crude oil from its producing assets where the sales price is determined based on benchmark crude oil price. The Group's exposure to commodity price risk arises primarily from their crude oil inventory as at the end of the reporting date.

Sensitivity analysis for commodity price risk

As at 31 December 2018, if the benchmark price of the crude oil had been 10% (2017: 10%) higher/lower with all other variables held constant, the Group's loss before tax would have been US$1.4 million (2017: US$1.2 million) lower/higher, arising as a result of higher/lower net realisable value of crude oil inventory.

Foreign currency risk

The Group's foreign currency exposure arises primarily from loans and borrowings denominated in Singapore Dollar ("SGD").

Sensitivity analysis for foreign currency risk

As at 31 December 2018, if SGD/USD had strengthened/weakened by 3% with all other variables held constant, the Group's loss before tax would have been US$7.4 million lower/ US$7.9 million higher (2017: US$7.0 million lower/ US$7.4 million higher), arising as a result of lower/higher carrying value of the loans and borrowings.

27 Capital management

Capital includes loans and borrowings, amount from offtakers for crude sales and equity attributable to owners of the Company as disclosed in the table below.

The Group manages its capital structure and makes adjustments to it, in light of changes in economic conditions. To maintain or adjust the capital structure, the Group may adjust the dividend payment to shareholders, return capital to shareholders or issue new shares. No changes were made in the objectives, policies or processes during the year ended 31 December 2018 and 31 December 2017.

The primary objective of the Group's capital management is to ensure that it maintains, among other things, healthy capital ratios in order to support its business and maximise shareholder value. The Group monitors capital using a gearing ratio, which is net debt divided by total capital plus net debt. Although the Group's policy is to maintain a gearing ratio within 30.0% to 50.0%, the Group's gearing ratio has increased year-on-year resulting in a ratio of 95.5% as at 31 December 2018. Such increase in the gearing ratio has been a result of an increase in interest-bearing debt obligations, net losses after tax, advanced crude sales and decrease in equity attributable to owners of the Company.

Although the Group benefitted from the general improvement in oil prices in 2018, the consequences of depressed and volatile oil markets from August 2014, coupled with the Group's high exposure to interest-bearing debt and associated non-cash finance charges, has materially and adversely impacted the Group's results of operations and financial condition. As at 31 December 2018, gearing was 95.5% (2017: 73.5%). The Group has been unable to materially improve liquidity largely due to covenants imposed by the Group's secured and unsecured lenders. The Group remains over-geared and under-equitised and has appointed advisers to formally evaluate and implement all viable options to improve the financial condition of the Group.

		GROUP
	2018 US$	**2017** US$
Loans and borrowings (Note 18)	459,072,439	424,612,597
Amount from offtakers for crude sales (Note 17)	23,300,089	18,990,117
Equity attributable to the owners of the Company	22,738,477	159,726,339
Capital and debt	505,111,005	603,329,053
Gearing ratio	95.5%	73.5%

28 Segment reporting

For management purposes, the Group operates in one business segment that is exploration and production of oil and gas in Asia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

				GROUP
		REVENUE		**NON-CURRENT ASSETS**
	2018	**2017** US$	**2018** US$	**2017** US$
Bangladesh	9,531,012	12,221,384	37,854,357	39,459,212
Cambodia	–	–	196,722,169	187,371,456
Indonesia	–	–	88,411,351	112,531,299
Thailand	135,274,404	128,478,829	165,635,635	202,263,098
Vietnam	–	–	4,954,217	36,429,829
	144,805,416	140,700,213	493,577,729	578,054,894

Non-current assets information presented above consists of exploration and evaluation assets, oil and gas properties, intangible assets and refurbishment assets as presented in the notes to the consolidated financial statements.

Information about major customers

The Group identifies a major customer as one who contributes to 10 per cent or more of the total revenue. As at 31 December 2018, revenue from one (2017: two) major customer(s) contributed to 76.0% (2017: 72.3% and 12.2%) of the Group's total revenue.

29 Contingent liabilities

Jefferies International Limited

As at 31 December 2018, Jefferies International Limited ("Jefferies") has commenced arbitration proceedings against the Company, seeking disputed success fees of US$1.75 million under an engagement letter for financial advisory services to the Company. The Company takes the view, in consultation with legal advisors, that the claim made by Jefferies is without merit. The Company is taking legal advice and intends to vigorously resist and refute Jefferies' claim. In addition, the Company fully reserves its rights to seek remedies, including any counterclaim and costs, against Jefferies to the fullest extent under the engagement letter and at law.

This claim is not expected to have any material impact on the Company's operations for the financial year ended 31 December 2018.

Rubicon Vantage International Pte Ltd

As at 31 December 2018, Rubicon Vantage International Pte Ltd ("Rubicon") has filed a Part 8 Claim Form in the High Court of Justice Business and Property Courts of England and Wales against the Company.

The claim alleged by Rubicon is in relation to a parent company guarantee ("Guarantee") made by the Company as guarantor to secure the performance of its subsidiary's, KrisEnergy (Gulf of Thailand) Ltd, obligations to Rubicon under a bareboat charterparty dated October 2014 ("Bareboat Charter"). Rubicon is seeking, amongst others, a declaration that it has made a compliant demand under the Guarantee in respect of the sum of approximately US$1.8 million.

The Company takes the view in consultation with legal advisors that Rubicon is not entitled to claim under the Guarantee as alleged, or at all, as the Guarantee is not an on demand guarantee and the underlying claims under the Bareboat Charter are invalid. The Company is taking legal advice and intends to vigorously resist and refute any and all allegations or claims made against it.

This claim is not expected to have any material impact on the Company's operations for the financial year ended 31 December 2018.

30 Authorisation of consolidated financial statements for issue

The consolidated financial statements for the year ended 31 December 2018 were authorised for issue in accordance with a resolution of the directors on 1 April 2019.

Shareholding and Warrantholding Statistics

Total number of issued Shares	:	1,502,849,065
Class of Shares	:	Ordinary Shares of US$0.00125 par value
Voting rights	:	1 vote per ordinary Share

Analysis of Shareholdings as at 15 March 2019:

SIZE OF SHAREHOLDINGS	NUMBER OF SHAREHOLDERS	%	NUMBER OF SHARES	%
1 - 99	70	2.33	688	0.00
100 - 1,000	155	5.15	110,140	0.01
1,001 - 10,000	767	25.50	5,058,783	0.33
10,001 - 1,000,000	1,944	64.63	227,662,609	15.15
1,000,001 and above	72	2.39	1,270,016,845	84.51
Total	3,008	100.00	1,502,849,065	100.00

Top Twenty Shareholders as at 15 March 2019:

NO.	NAME OF SHAREHOLDER	NUMBER OF SHARES	%
1.	BNP Paribas Nominees Singapore Pte Ltd	598,263,893	39.81
2.	DBS Nominees Pte Ltd	205,190,824	13.65
3.	Citibank Nominees Singapore Pte Ltd	147,038,538	9.78
4.	Raffles Nominees (Pte) Limited	56,592,642	3.77
5.	Morgan Stanley Asia (S) Securities Pte Ltd	23,773,494	1.58
6.	CGS-CIMB Securities (Singapore) Pte Ltd	18,082,352	1.20
7.	OCBC Securities Private Ltd	16,640,907	1.11
8.	Phillip Securities Pte Ltd	16,297,642	1.08
9.	Maybank Kim Eng Securities Pte. Ltd.	12,843,160	0.85
10.	UOB Kay Hian Pte Ltd	11,448,340	0.76
11.	Lin Yuanfeng	10,000,000	0.67
12.	Lim And Tan Securities Pte Ltd	8,525,000	0.57
13.	Waterworth Pte Ltd	8,000,000	0.53
14.	Khoo Yee Hock	7,000,000	0.47
15.	DBS Vickers Securities (S) Pte Ltd	6,707,600	0.45
16.	Coffee Express 2000 Pte Ltd	6,200,000	0.41
17.	Aw Guan Hong	5,000,000	0.33
18.	Cheung Lap Yuen	4,978,000	0.33
19.	Lim Chor Teck Aaron	4,514,800	0.30
20.	Tan Seng Hock	3,985,000	0.27
		1,171,082,192	**77.92**

Substantial Shareholders as at 15 March 2019:

	HOLDINGS REGISTERED IN NAME OF SUBSTANTIAL SHAREHOLDERS OR NOMINEES		HOLDINGS IN WHICH SUBSTANTIAL SHAREHOLDERS ARE DEEMED TO HAVE AN INTEREST IN		TOTAL SHAREHOLDING	
	Number of Shares	%[1]	Number of Shares	%[1]	Number of Shares	%[1]
Keppel Oil & Gas Pte Ltd	598,263,893	39.81	–	–	598,263,893	39.81
Kepventure Pte Ltd	–	–	598,263,893[2]	39.81	598,263,893	39.81
Keppel Corporation Limited	–	–	598,263,893[2]	39.81	598,263,893	39.81
Temasek Holdings (Private) Limited	–	–	598,263,893[3]	39.81	598,263,893	39.81
Serle Investments Limited	175,421,133	11.67	–	–	175,421,133	11.67
Yeoh Sock Siong	–	–	175,421,133[4]	11.67	175,421,133	11.67
Tan Siew Bee	–	–	175,421,133[4]	11.67	175,421,133	11.67
Ng Kay Yip	142,224,097	9.46	–	–	142,224,097	9.46

NOTES

1 Based on 1,502,849,065 issued Shares as at the Latest Practicable Date.

2 Kepventure Pte Ltd ("**KPL**") and KCL are each deemed under Section 4 of the Singapore Securities and Futures Act to have an interest in the Shares held by Keppel Oil & Gas Pte Ltd ("**KOG**") as:
(a) KOG is a wholly owned subsidiary of KPL; and
(b) KPL is a wholly owned subsidiary of KCL.

3 Temasek Holdings (Private) Limited ("**Temasek**") is deemed under Section 4 of the Singapore Securities and Futures Act to have an interest in the Shares held by KOG as:
(a) KOG is a wholly owned subsidiary of KPL;
(b) KPL is a wholly owned subsidiary of KCL; and
(c) Temasek has more than 20% interest in KCL, an independently managed Temasek portfolio company.

4 Yeoh Sock Siong and Tan Siew Bee (being spouses) are each deemed under Section 4 of the Singapore Securities and Futures Act to have an interest in the Shares held by Serle Investments Limited as they hold the entire issued share capital of Serle Investments Limited.

Public Shareholders

Based on the information available to our Company as at 15 March 2019, approximately 38.84% of the issued shares of our Company is held by the public and therefore, pursuant to Rules 1207 and 723 of the Listing Manual of the Singapore Exchange Securities Trading Limited, it is confirmed that at least 10% of the ordinary shares of our Company is at all times held by the public.

Treasury Shares

As at 15 March 2019, the Company does not hold any treasury shares or subsidiary holdings.

Analysis of Warrantholdings as at 15 March 2019:

SIZE OF WARRANTHOLDINGS	NUMBER OF WARRANTHOLDERS	%	NUMBER OF WARRANTS	%
1 - 99	23	3.99	1,147	0.00
100 - 1,000	8	1.39	5,560	0.00
1,001 - 10,000	75	13.02	561,331	0.04
10,001 - 1,000,000	420	72.92	75,354,378	6.01
1,000,001 and above	50	8.68	1,179,249,840	93.95
	576	**100.00**	**1,255,172,256**	**100.00**

Top Twenty Warrantholders as at 15 March 2019:

NO.	NAME OF WARRANTHOLDER	NUMBER OF WARRANTS	%
1.	BNP Paribas Nominees Singapore Pte Ltd	964,853,865	76.87
2.	Waterworth Pte Ltd	25,000,000	1.99
3.	Citibank Nominees Singapore Pte Ltd	18,613,701	1.48
4.	DBS Nominees Pte Ltd	12,366,275	0.99
5.	Teo Chiang Song	12,000,000	0.96
6.	DBS Vickers Securities (S) Pte Ltd	9,117,645	0.73
7.	Lee Yuen Shih	9,000,000	0.72
8.	CGS-CIMB Securities (Singapore) Pte Ltd	7,379,486	0.59
9.	Teo Chiang Wee	7,000,000	0.56
10.	OCBC Securities Private Ltd	6,458,013	0.51
11.	Maybank Kim Eng Securities Pte.Ltd.	6,330,986	0.50
12.	Neo Kim Kuek	5,700,000	0.45
13.	Tan Siew Lin	5,570,000	0.44
14.	Ng Pock Hoe	5,000,000	0.40
15.	UOB Kay Hian Pte Ltd	4,909,596	0.39
16.	Yip Wai Mun	4,880,000	0.39
17.	Phillip Securities Pte Ltd	4,688,147	0.37
18.	Kuan Kok Siang	4,490,000	0.36
19.	Ng Chee Fatt	4,270,000	0.34
20.	Zhuo Jingming	4,200,000	0.33
		1,121,827,714	**89.37**

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG · MIKE K. NORTON
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CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

January 25, 2019

Board of Directors
KrisEnergy (Asia) Ltd
83 Clemenceau Avenue
10-05, UE Square, Shell House
Singapore 239920

Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2018, to the KrisEnergy (Asia) Ltd (referred to herein as "KrisEnergy") interest in certain oil and gas properties located in Blocks B8/32 and B9A, Rossukon Field, and Wassana Field, offshore Thailand; Lengo Field, offshore Indonesia; Block A, offshore Cambodia; and Bangora Field, onshore Bangladesh. Also as requested, we have estimated the development unclarified contingent resources, as of December 31, 2018, to the KrisEnergy working interest in certain other discoveries located offshore Thailand, offshore Indonesia, offshore Cambodia, and onshore Bangladesh. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by KrisEnergy, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. The tables following the definitions include summaries of our estimates of reserves and contingent resources, by category, to the KrisEnergy interest for each asset area and reconciliation tables for reserves and contingent resources.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) reserves and working interest reserves and future net revenue to the KrisEnergy interest in these properties, as of December 31, 2018, to be:

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Category	Gross (100%) Reserves Oil (MBBL)	Gross (100%) Reserves Gas (MMCF)	Working Interest Reserves Oil (MBBL)	Working Interest Reserves Gas (MMCF)	Future Net Revenue[1] (M$) Total	Future Net Revenue[1] (M$) Present Worth at 10%
Proved Developed Producing	13,156.9	219,667.0	2,236.9	57,277.1	(64,673.1)[2]	(57,855.3)[2]
Proved Developed Non-Producing	55.2	25,121.2	16.6	7,536.4	5,330.9	2,698.5
Proved Undeveloped	3,115.2	0.0	2,772.5	0.0	97,595.8	83,744.9
Proved (1P)	16,327.3	244,788.3	5,026.0	64,813.5	38,253.6	28,588.1
Probable	71,616.5	659,326.0	16,781.2	185,256.3	388,482.8	194,542.5
Proved + Probable (2P)	87,943.8	904,114.3	21,807.2	250,069.7	426,736.4	223,130.7
Possible	28,962.2	211,558.4	10,186.9	53,312.4	313,134.7	197,045.7
Proved + Probable + Possible (3P)	116,906.0	1,115,672.7	31,994.1	303,382.1	739,871.1	420,176.4

Totals may not add because of rounding.

(1) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried costs and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, value-added taxes, and income taxes.

(2) Future net revenue is negative after deducting estimated abandonment costs and all proved operating costs.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves is KrisEnergy's share of the gross (100 percent) revenue from the properties after deductions for royalties. Future net revenue is after additional deductions for KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried costs and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, value-added taxes, and income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the KrisEnergy interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on KrisEnergy receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The discoveries assessed in this report have been subclassified as development unclarified. The 2018 PRMS defines a development unclarified discovery as a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The contingent resources shown in this report are contingent upon one or more of the following: (1) collection of additional technical data, to be gathered through delineation wells and flow tests, to establish commercial viability, (2) finalization of a plan to develop the resources, (3) commitment of the license partners to develop the resources, (4) submission and approval of a Plan of Development, Production Area Application, or Production Permit Application, and (5) completion of a gas sales agreement. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for these properties. Because of the early stage of development of these projects, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the gross (100 percent) contingent resources and working interest contingent resources to the KrisEnergy interest in these discoveries, as of December 31, 2018, to be:

Subclassification/ Category	Gross (100%) Contingent Resources Oil (MBBL)	Gross (100%) Contingent Resources Gas (MMCF)	Working Interest Contingent Resources Oil (MBBL)	Working Interest Contingent Resources Gas (MMCF)
Development Unclarified				
Low Estimate (1C)	6,990.2	54,792.6	6,262.2	42,133.2
Best Estimate (2C)	12,331.1	372,950.8	11,011.8	318,376.6
High Estimate (3C)	19,701.5	725,496.4	17,402.6	581,829.6

Note: Contingent resources are the arithmetic sum of multiple asset-level probability distributions.

The oil volumes shown include crude oil and condensate.

The contingent resources shown in this report have been estimated using a combination of deterministic and probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk. As recommended in the PRMS, the 1C, 2C, and 3C contingent resources have been aggregated beyond the field level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

ECONOMIC PARAMETERS

As requested, this report has been prepared using oil and gas price parameters specified by KrisEnergy. Oil prices for the reserves are based on the average forecast for Brent Crude prices from an aggregation of several independent public forecasts and are adjusted by area for quality, transportation fees, and market differentials. The oil prices, before adjustments, are shown in the following table:

Period Ending	Oil Price ($/Barrel)
12-31-2019	73.00
12-31-2020	71.00
12-31-2021	70.00
Thereafter	71.00

Gas prices for Block B8/32 and Block B9A reserves for January through March 2019 are based on the Tantawan Gas Sales Agreement price of $4.716 per MMBTU and are adjusted by field area for energy content. Gas prices starting in April 2019 are based on the Tantawan Gas Sales Agreement pricing formula and the oil prices shown in the table above and are adjusted by field area for energy content. The gas prices, before adjustments, are shown in the following table:

Period Ending	Gas Price ($/MMBTU)
3-31-2019	4.716
12-31-2019	4.703
12-31-2020	4.599
12-31-2021	4.562
Thereafter	4.599

The gas price for Bangora Field reserves is the contract price of $2.319 per MCF. Gas prices for Bangora Field are held constant throughout the lives of the properties.

The gas price for Lengo Field reserves is based on recent gas contracts in similar areas and is $6.250 per MMBTU; this price is adjusted for energy content and is escalated 2 percent per year from the year of first production throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of and budgets prepared by the operators of the properties, as provided by KrisEnergy. These costs include the per-well overhead expenses allowed under concession agreements along with estimates of costs to be incurred at and below the field level. Headquarters general and administrative overhead expenses of KrisEnergy are included to the extent that they are covered under concession agreements for the operated properties. As requested, abandonment costs for the assets located offshore Indonesia are included as operating costs. Also as requested, operating costs are not escalated for inflation.

Capital costs used in this report were provided by KrisEnergy and are based on budgeted expenditures and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are KrisEnergy's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. For all assets not located offshore Indonesia, abandonment costs are shown herein as capital costs; abandonment costs for offshore Indonesia will be paid in installments and are included as operating costs. As requested, capital costs and abandonment costs are not escalated for inflation.

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by KrisEnergy, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. The contingent resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from KrisEnergy, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
Philip S. (Scott) Frost, P.E. 88738
Senior Vice President

Date Signed: January 25, 2019

PSF:EAP

STATE OF TEXAS
P. S. FROST
88738
LICENSED
PROFESSIONAL ENGINEER

By:
Allen E. Evans, Jr., P.G. 1286
Vice President

Date Signed: January 25, 2019

STATE OF TEXAS
A. E. EVANS, JR.
GEOLOGY
1286
LICENSED
PROFESSIONAL GEOSCIENTIST

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

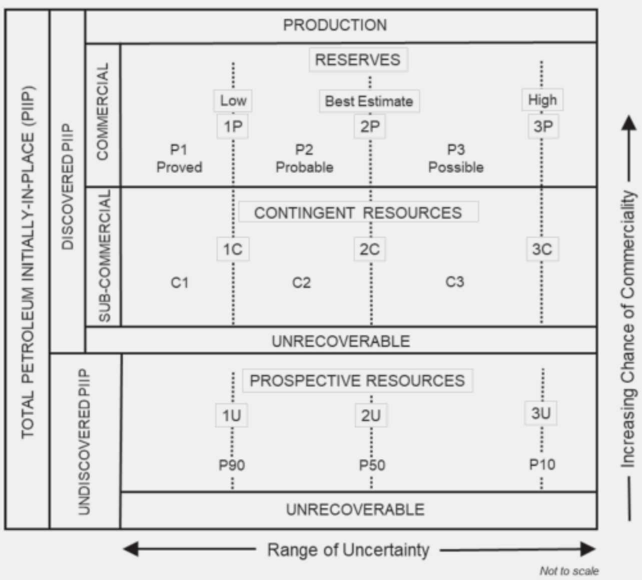

Figure 1.1—Resources classification framework

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

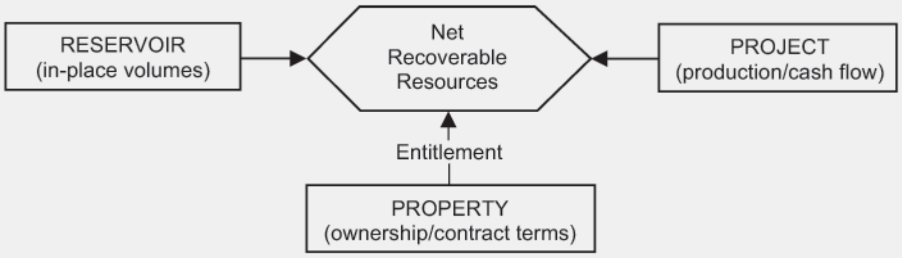

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2018

	Gross (100%) Reserves		Working Interest Reserves[1]		Net Reserves[2]		Future Net Revenue[3] (M$)	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Offshore Thailand								
Blocks B8/32 and B9A								
Proved Developed Producing	10,932.5	33,995.1	506.7	1,575.5	463.8	1,485.1	(7,434.4)[4]	(4,828.4)[4]
Proved (1P)	10,932.5	33,995.1	506.7	1,575.5	463.8	1,485.1	(7,434.4)[4]	(4,828.4)[4]
Probable	49,765.6	226,133.9	2,306.4	10,480.2	2,087.5	9,752.2	56,320.6	40,058.0
Proved + Probable (2P)	60,698.1	260,129.0	2,813.1	12,055.7	2,551.3	11,237.3	48,886.3	35,229.6
Possible	16,570.9	70,121.5	768.0	3,249.8	670.7	2,936.5	32,796.2	18,554.4
Proved + Probable + Possible (3P)	77,269.0	330,250.5	3,581.0	15,305.5	3,222.0	14,173.8	81,682.5	53,784.0
Block G6/48, Rossukon Field								
Probable	11,700.0	0.0	5,031.0	0.0	4,698.4	0.0	42,330.1	24,020.7
Proved + Probable (2P)	11,700.0	0.0	5,031.0	0.0	4,698.4	0.0	42,330.1	24,020.7
Possible	4,100.0	0.0	1,763.0	0.0	1,600.9	0.0	32,667.3	23,870.7
Proved + Probable + Possible (3P)	15,800.0	0.0	6,794.0	0.0	6,299.4	0.0	74,997.4	47,891.4
Block G10/48, Wassana Field								
Proved Developed Producing	1,801.6	0.0	1,603.4	0.0	1,519.6	0.0	(94,637.6)[4]	(80,421.2)[4]
Proved Undeveloped	3,115.2	0.0	2,772.5	0.0	2,600.9	0.0	97,595.8	83,744.9
Proved (1P)	4,916.7	0.0	4,375.9	0.0	4,120.5	0.0	2,958.2	3,323.7
Probable	1,439.7	0.0	1,281.4	0.0	1,178.3	0.0	48,801.9	42,016.0
Proved + Probable (2P)	6,356.5	0.0	5,657.3	0.0	5,298.8	0.0	51,760.1	45,339.7
Possible	1,692.2	0.0	1,506.1	0.0	1,380.6	0.0	57,377.6	48,898.8
Proved + Probable + Possible (3P)	8,048.7	0.0	7,163.4	0.0	6,679.4	0.0	109,137.7	94,238.5
Offshore Indonesia								
Bulu PSC, Lengo Field								
Probable	0.0	358,547.6	0.0	152,382.7	0.0	108,668.6	202,211.5	72,965.3
Proved + Probable (2P)	0.0	358,547.6	0.0	152,382.7	0.0	108,668.6	202,211.5	72,965.3
Possible	0.0	61,052.4	0.0	25,947.3	0.0	15,918.5	40,653.7	7,815.6
Proved + Probable + Possible (3P)	0.0	419,600.0	0.0	178,330.0	0.0	124,587.1	242,865.3	80,780.9

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

(1) KrisEnergy's current working interest is 4.6345 percent in Blocks B8/32 and B9A, 43.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 42.5000 percent in the Bulu PSC, 95.0000 percent in Block A, and 30.0000 percent in Bangora Field.

(2) Net reserves are the portion of gross reserves representing KrisEnergy's revenue entitlement.

(3) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried costs and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, value-added taxes, and income taxes.

(4) Future net revenue is negative after deducting estimated abandonment costs and all proved operating costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Page 1

SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2018

	Gross (100%) Reserves		Working Interest Reserves(1)		Net Reserves(2)		Future Net Revenue(3) (M$)	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Offshore Cambodia								
Block A, Apsara Field, Platform A								
Probable	8,537.1	0.0	8,110.2	0.0	6,516.4	0.0	22,818.4	7,786.4
Proved + Probable (2P)	8,537.1	0.0	8,110.2	0.0	6,516.4	0.0	22,818.4	7,786.4
Possible	6,415.6	0.0	6,094.8	0.0	4,789.9	0.0	133,108.5	91,603.9
Proved + Probable + Possible (3P)	14,952.7	0.0	14,205.1	0.0	11,306.3	0.0	155,926.9	99,390.3
Onshore Bangladesh								
Block 9, Bangora Field								
Proved Developed Producing	422.8	185,672.0	126.8	55,701.6	39.4	26,034.4	37,398.8	27,394.4
Proved Developed Non-Producing	55.2	25,121.2	16.6	7,536.4	4.7	3,311.1	5,330.9	2,698.5
Proved (1P)	478.0	210,793.2	143.4	63,237.9	44.2	29,345.5	42,729.7	30,092.8
Probable	174.2	74,644.5	52.3	22,393.4	15.3	9,817.5	16,000.2	7,696.2
Proved + Probable (2P)	652.2	285,437.7	195.7	85,631.3	59.4	39,163.0	58,730.0	37,789.0
Possible	183.4	80,384.5	55.0	24,115.4	17.9	11,119.6	16,531.4	6,302.3
Proved + Probable + Possible (3P)	835.6	365,822.2	250.7	109,746.7	77.4	50,282.6	75,261.3	44,091.3
Total								
Proved Developed Producing	13,156.9	219,667.0	2,236.9	57,277.1	2,022.8	27,519.5	(64,673.1) (4)	(57,855.3) (4)
Proved Developed Non-Producing	55.2	25,121.2	16.6	7,536.4	4.7	3,311.1	5,330.9	2,698.5
Proved Undeveloped	3,115.2	0.0	2,772.5	0.0	2,600.9	0.0	97,595.8	83,744.9
Proved (1P)	16,327.3	244,788.3	5,026.0	64,813.5	4,628.4	30,830.6	38,253.6	28,588.1
Probable	71,616.5	659,326.0	16,781.2	185,256.3	14,495.9	128,238.3	388,482.8	194,542.5
Proved + Probable (2P)	87,943.8	904,114.3	21,807.2	250,069.7	19,124.3	159,068.9	426,736.4	223,130.7
Possible	28,962.2	211,558.4	10,186.9	53,312.4	8,460.1	29,974.6	313,134.7	197,045.7
Proved + Probable + Possible (3P)	116,906.0	1,115,672.7	31,994.1	303,382.1	27,584.4	189,043.5	739,871.1	420,176.4

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

(1) KrisEnergy's current working interest is 4.6345 percent in Blocks B8/32 and B9A, 43.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 42.5000 percent in the Bulu PSC, 95.0000 percent in Block A, and 30.0000 percent in Bangora Field.

(2) Net reserves are the portion of gross reserves representing KrisEnergy's revenue entitlement.

(3) Future net revenue is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, carried costs and reimbursements associated with local participation, head office overhead, production bonus payments, special remuneratory benefit, value-added taxes, and income taxes.

(4) Future net revenue is negative after deducting estimated abandonment costs and all proved operating costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF DEVELOPMENT UNCLARIFIED
CONTINGENT RESOURCES
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2018

	Gross (100%) Contingent Resources		Working Interest Contingent Resources[1]	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Offshore Thailand				
Block G6/48, Rossukon Field				
Low Estimate (1C)	0.0	11,476.9	0.0	4,935.1
Best Estimate (2C)	0.0	13,238.4	0.0	5,692.5
High Estimate (3C)	0.0	15,369.3	0.0	6,608.8
Block G10/48, Wassana Field				
Low Estimate (1C)	5,605.8	0.0	4,989.2	0.0
Best Estimate (2C)	9,338.1	0.0	8,310.9	0.0
High Estimate (3C)	12,906.7	0.0	11,486.9	0.0
Block G10/48, Mayura Field				
Low Estimate (1C)	453.7	0.0	403.8	0.0
Best Estimate (2C)	1,140.3	0.0	1,014.9	0.0
High Estimate (3C)	3,124.7	0.0	2,781.0	0.0
Offshore Indonesia				
Bala-Balakang PSC, Halimun and Papandayan Discoveries				
Low Estimate (1C)	0.0	0.0	0.0	0.0
Best Estimate (2C)	0.0	110,510.4	0.0	93,933.9
High Estimate (3C)	0.0	155,810.7	0.0	132,439.1
Sakti PSC, Mustika Field				
Low Estimate (1C)	0.0	37,236.1	0.0	35,374.3
Best Estimate (2C)	0.0	221,522.6	0.0	210,446.5
High Estimate (3C)	0.0	425,364.3	0.0	404,096.1

(1) KrisEnergy's current working interest is 43.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 85.0000 percent in the Bala-Balakang PSC, 95.0000 percent in the Sakti PSC, 95.0000 percent in Block A, and 30.0000 percent in Block 9. It is anticipated that local participation will reduce the current working interest proportionately in the Bala-Balakang and Sakti PSCs based on the local participant obtaining a 10.0000 percent interest in the asset. Working interest contingent resources are estimated based on the current working interest.

(2) Totals are the arithmetic sum of multiple asset-level probability distributions.

SUMMARY OF DEVELOPMENT UNCLARIFIED
CONTINGENT RESOURCES
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2018

	Gross (100%) Contingent Resources		Working Interest Contingent Resources[1]	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Offshore Cambodia				
Block A, Apsara Field, Platform B				
Low Estimate (1C)	762.1	0.0	724.0	0.0
Best Estimate (2C)	1,423.8	0.0	1,352.6	0.0
High Estimate (3C)	2,476.6	0.0	2,352.8	0.0
Block A, Apsara Field, Platform C				
Low Estimate (1C)	145.6	0.0	138.3	0.0
Best Estimate (2C)	314.9	0.0	299.2	0.0
High Estimate (3C)	652.0	0.0	619.4	0.0
Onshore Bangladesh				
Block 9, Lalmai Field				
Low Estimate (1C)	23.0	6,079.6	6.9	1,823.9
Best Estimate (2C)	113.9	27,679.3	34.2	8,303.8
High Estimate (3C)	541.5	128,952.1	162.4	38,685.6
Total[2]				
Low Estimate (1C)	6,990.2	54,792.6	6,262.2	42,133.2
Best Estimate (2C)	12,331.1	372,950.8	11,011.8	318,376.6
High Estimate (3C)	19,701.5	725,496.4	17,402.6	581,829.6

(1) KrisEnergy's current working interest is 43.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 85.0000 percent in the Bala-Balakang PSC, 95.0000 percent in the Sakti PSC, 95.0000 percent in Block A, and 30.0000 percent in Block 9. It is anticipated that local participation will reduce the current working interest proportionately in the Bala-Balakang and Sakti PSCs based on the local participant obtaining a 10.0000 percent interest in the asset. Working interest contingent resources are estimated based on the current working interest.

(2) Totals are the arithmetic sum of multiple asset-level probability distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

RESERVES RECONCILIATION
DECEMBER 31, 2017 TO DECEMBER 31, 2018
KRISENERGY (ASIA) LTD INTEREST

	Gross (100%) Reserves				Working Interest Reserves			
	as of December 31, 2018		Percent Difference[1]		as of December 31, 2018		Percent Difference[1]	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Offshore Thailand								
Blocks B8/32 and B9A[2][3]								
Proved (1P)	10,932.5	33,995.1	46.4	6.4	506.7	1,575.5	46.4	6.4
Proved + Probable (2P)	60,698.1	260,129.0	(16.5)	(40.6)	2,813.1	12,055.7	(16.5)	(40.6)
Proved + Probable + Possible (3P)	77,269.0	330,250.5	(12.2)	(39.5)	3,581.0	15,305.5	(12.2)	(39.5)
Block G6/48, Rossukon Field[4]								
Proved (1P)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved + Probable (2P)	11,700.0	0.0	0.0	0.0	5,031.0	0.0	43.3	0.0
Proved + Probable + Possible (3P)	15,800.0	0.0	0.0	0.0	6,794.0	0.0	43.3	0.0
Block G10/48, Wassana Field[5]								
Proved (1P)	4,916.7	0.0	(42.3)	0.0	4,375.9	0.0	(42.3)	0.0
Proved + Probable (2P)	6,356.5	0.0	(53.2)	0.0	5,657.3	0.0	(53.2)	0.0
Proved + Probable + Possible (3P)	8,048.7	0.0	(50.2)	0.0	7,163.4	0.0	(50.2)	0.0
Block G11/48, Nong Yao Field[6]								
Proved (1P)			(100.0)	0.0			(100.0)	0.0
Proved + Probable (2P)			(100.0)	0.0			(100.0)	0.0
Proved + Probable + Possible (3P)			(100.0)	0.0			(100.0)	0.0
Offshore Indonesia								
Bulu PSC, Lengo Field								
Proved (1P)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved + Probable (2P)	0.0	358,547.6	0.0	0.0	0.0	152,382.7	0.0	0.0
Proved + Probable + Possible (3P)	0.0	419,600.0	0.0	0.0	0.0	178,330.0	0.0	0.0
Onshore Indonesia								
Block A Aceh[6]								
Proved (1P)			(100.0)	(100.0)			(100.0)	(100.0)
Proved + Probable (2P)			(100.0)	(100.0)			(100.0)	(100.0)
Proved + Probable + Possible (3P)			(100.0)	(100.0)			(100.0)	(100.0)
Offshore Cambodia								
Block A, Apsara Field, Platform A								
Proved (1P)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved + Probable (2P)	8,537.1	0.0	0.0	0.0	8,110.2	0.0	(0.0)	0.0
Proved + Probable + Possible (3P)	14,952.7	0.0	0.0	0.0	14,205.1	0.0	0.0	0.0
Onshore Bangladesh								
Block 9, Bangora Field[7]								
Proved (1P)	478.0	210,793.2	(20.9)	1.1	143.4	63,237.9	(20.9)	1.1
Proved + Probable (2P)	652.2	285,437.7	(19.9)	(11.7)	195.7	85,631.3	(19.9)	(11.7)
Proved + Probable + Possible (3P)	835.6	365,822.2	(18.8)	(11.0)	250.7	109,746.7	(18.8)	(11.0)
Total								
Proved (1P)	16,327.3	244,788.3	(35.6)	(50.4)	5,026.0	64,813.5	(48.8)	(36.4)
Proved + Probable (2P)	87,943.8	904,114.3	(26.7)	(38.5)	21,807.2	250,069.7	(26.8)	(22.4)
Proved + Probable + Possible (3P)	116,906.0	1,115,672.7	(23.1)	(35.7)	31,994.1	303,382.1	(21.6)	(20.3)

(1) A positive percent difference indicates higher reserves for year-end 2018 compared to year-end 2017. A negative percent difference indicates lower reserves for year-end 2018 compared to year-end 2017.
(2) Year-end 2018 1P reserves for Blocks B8/32 and B9A are higher because of improved economic conditions. Year-end 2018 2P and 3P reserves for Blocks B8/32 and B9A are lower because of reduced long-term drilling plans and reduced remaining life to the end of concession.
(3) Tantawan Field in Block B8/32 and Rajpruek Field in Block B9A ceased operation on October 31, 2017. Abandonment activities are underway before the B9A concession is relinquished.
(4) Year-end 2018 working interest reserves are higher because the economic interest in the production area of Block G6/48 increased from 30 to 43 percent.
(5) Year-end 2018 reserves for Block G10/48 are lower because of lower well performance and reduced recovery for future wells.
(6) KrisEnergy ceased participation in Block G11/48 and Block A Aceh in late 2017 to early 2018.
(7) Year-end 2018 reserves for Block 9 are lower because of 2018 production volumes and increased off-block recovery. In the 1P case, this decrease is offset by a well recompletion to the A, B, and C sands.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

CONTINGENT RESOURCES RECONCILIATION
DECEMBER 31, 2017 TO DECEMBER 31, 2018
KRISENERGY (ASIA) LTD INTEREST

	Gross (100%) Contingent Resources[1]				Working Interest Contingent Resources[1]			
	as of December 31, 2018		Percent Difference[2]		as of December 31, 2018		Percent Difference[2]	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Offshore Thailand								
Block G6/48, Rossukon Field[3]								
Low Estimate (1C)	0.0	11,476.9	0.0	0.0	0.0	4,935.1	0.0	43.3
Best Estimate (2C)	0.0	13,238.4	0.0	0.0	0.0	5,692.5	0.0	43.3
High Estimate (3C)	0.0	15,369.3	0.0	0.0	0.0	6,608.8	0.0	43.3
Block G10/48, Wassana Field[4]								
Low Estimate (1C)	5,605.8	0.0	107.6	0.0	4,989.2	0.0	107.6	0.0
Best Estimate (2C)	9,338.1	0.0	139.7	0.0	8,310.9	0.0	139.7	0.0
High Estimate (3C)	12,906.7	0.0	138.1	0.0	11,486.9	0.0	138.1	0.0
Block G10/48, Mayura Field								
Low Estimate (1C)	453.7	0.0	0.0	0.0	403.8	0.0	0.0	0.0
Best Estimate (2C)	1,140.3	0.0	0.0	0.0	1,014.9	0.0	0.0	0.0
High Estimate (3C)	3,124.7	0.0	0.0	0.0	2,781.0	0.0	0.0	0.0
Block G11/48, Angun Field[5]								
Low Estimate (1C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
Best Estimate (2C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
High Estimate (3C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
Block G11/48, Mantana Field[5]								
Low Estimate (1C)			0.0	(100.0)	0.0	0.0	0.0	(100.0)
Best Estimate (2C)			0.0	(100.0)	0.0	0.0	0.0	(100.0)
High Estimate (3C)			0.0	(100.0)	0.0	0.0	0.0	(100.0)
Block G11/48, Nong Yao Field[5]								
Low Estimate (1C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
Best Estimate (2C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
High Estimate (3C)			(100.0)	0.0	0.0	0.0	(100.0)	0.0
Offshore Indonesia								
Bala-Balakang PSC, Halimun and Papandayan Discoveries								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	0.0	110,510.4	0.0	0.0	0.0	93,933.9	0.0	0.0
High Estimate (3C)	0.0	155,810.7	0.0	0.0	0.0	132,439.1	0.0	0.0
Sakti PSC, Mustika Field								
Low Estimate (1C)	0.0	37,236.1	0.0	0.0	0.0	35,374.3	0.0	0.0
Best Estimate (2C)	0.0	221,522.6	0.0	0.0	0.0	210,446.5	0.0	0.0
High Estimate (3C)	0.0	425,364.3	0.0	0.0	0.0	404,096.1	0.0	0.0

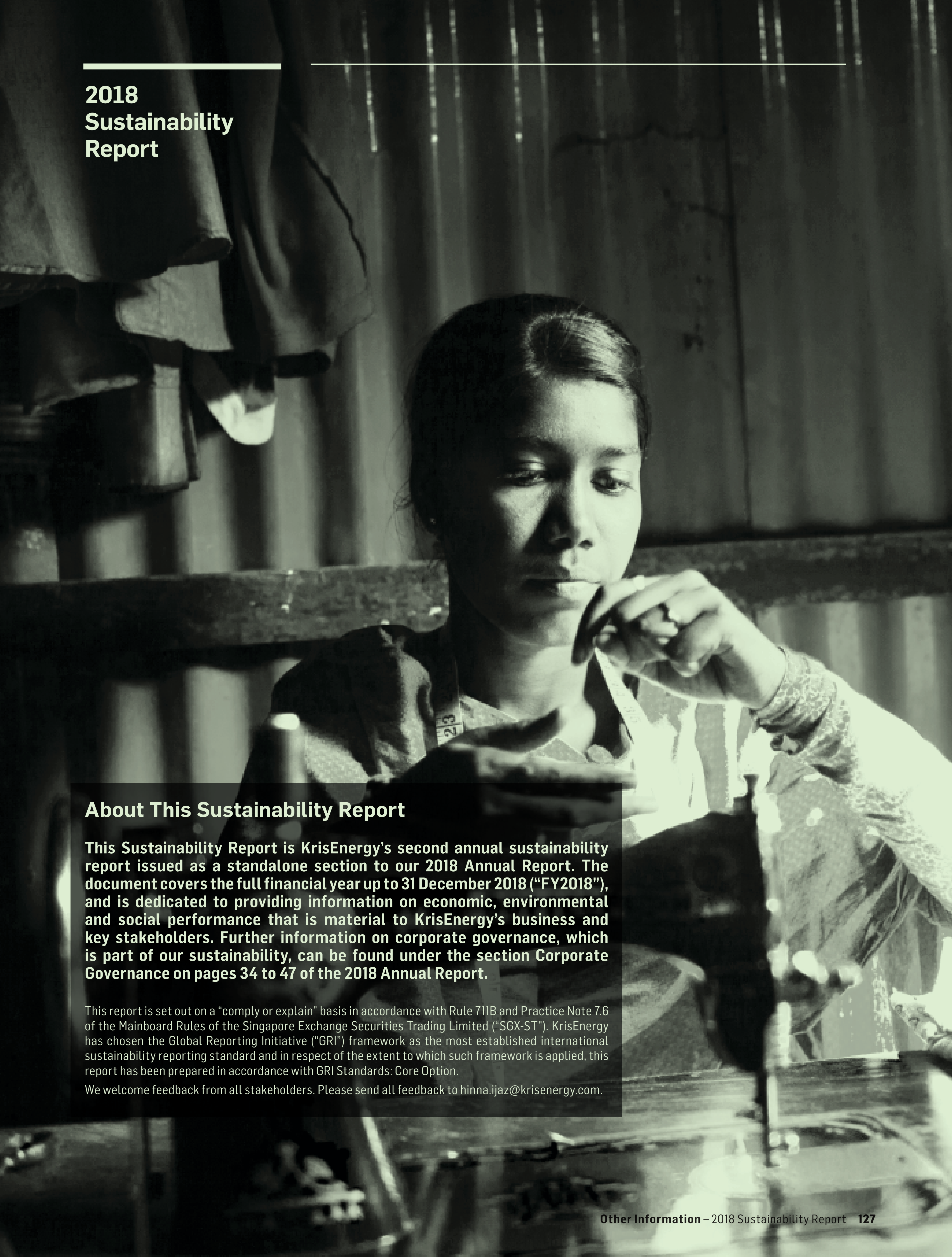
(1) For discussion of risk factors associated with contingent resources, refer to the 2018 PRMS definitions.
(2) A positive percent difference indicates higher contingent resources for year-end 2018 compared to year-end 2017. A negative percent difference indicates lower contingent resources for year-end 2018 compared to year-end 2017.
(3) Year-end 2018 working interest reserves are higher because the economic interest in the production area of Block G6/48 increased from 30 to 43 percent.
(4) Year-end 2018 contingent resources are higher for Block G10/48 because of the addition of Extension volumes in 2018. These volumes are associated with reservoirs for which reserves have been estimated that are beyond the economic limit of those reserves.
(5) KrisEnergy ceased participation in Block G11/48 and Block A Aceh in late 2017 to early 2018.
(6) Totals are the arithmetic sum of multiple asset-level probability distributions.

CONTINGENT RESOURCES RECONCILIATION
DECEMBER 31, 2017 TO DECEMBER 31, 2018
KRISENERGY (ASIA) LTD INTEREST

	Gross (100%) Contingent Resources[1]				Working Interest Contingent Resources[1]			
	as of December 31, 2018		Percent Difference[2]		as of December 31, 2018		Percent Difference[2]	
Country/Asset/Project/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Onshore Indonesia								
Block A Aceh[5]								
Low Estimate (1C)			(100.0)	(100.0)			(100.0)	(100.0)
Best Estimate (2C)			(100.0)	(100.0)			(100.0)	(100.0)
High Estimate (3C)			(100.0)	(100.0)			(100.0)	(100.0)
Offshore Cambodia								
Block A, Apsara Field, Platform B								
Low Estimate (1C)	762.1	0.0	0.0	0.0	724.0	0.0	0.0	0.0
Best Estimate (2C)	1,423.8	0.0	0.0	0.0	1,352.6	0.0	0.0	0.0
High Estimate (3C)	2,476.6	0.0	0.0	0.0	2,352.8	0.0	0.0	0.0
Block A, Apsara Field, Platform C								
Low Estimate (1C)	145.6	0.0	0.0	0.0	138.3	0.0	0.0	0.0
Best Estimate (2C)	314.9	0.0	0.0	0.0	299.2	0.0	0.0	0.0
High Estimate (3C)	652.0	0.0	0.0	0.0	619.4	0.0	0.0	0.0
Onshore Bangladesh								
Block 9, Lalmai Field								
Low Estimate (1C)	23.0	6,079.6	0.0	0.0	6.9	1,823.9	0.0	0.0
Best Estimate (2C)	113.9	27,679.3	0.0	0.0	34.2	8,303.8	0.0	0.0
High Estimate (3C)	541.5	128,952.1	0.0	0.0	162.4	38,685.6	0.0	0.0
Total[6]								
Low Estimate (1C)	6,990.2	54,792.6	6.1	(94.0)	6,262.2	42,133.2	50.3	(75.3)
Best Estimate (2C)	12,331.1	372,950.8	22.5	(75.1)	11,011.8	318,376.6	61.8	(34.5)
High Estimate (3C)	19,701.5	725,496.4	(47.5)	(69.3)	17,402.6	581,829.6	7.1	(29.7)

(1) For discussion of risk factors associated with contingent resources, refer to the 2018 PRMS definitions.
(2) A positive percent difference indicates higher contingent resources for year-end 2018 compared to year-end 2017. A negative percent difference indicates lower contingent resources for year-end 2018 compared to year-end 2017.
(3) Year-end 2018 working interest reserves are higher because the economic interest in the production area of Block G6/48 increased from 30 to 43 percent.
(4) Year-end 2018 contingent resources are higher for Block G10/48 because of the addition of Extension volumes in 2018. These volumes are associated with reservoirs for which reserves have been estimated that are beyond the economic limit of those reserves.
(5) KrisEnergy ceased participation in Block G11/48 and Block A Aceh in late 2017 to early 2018.
(6) Totals are the arithmetic sum of multiple asset-level probability distributions.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.



2018 Sustainability Report

About This Sustainability Report

This Sustainability Report is KrisEnergy's second annual sustainability report issued as a standalone section to our 2018 Annual Report. The document covers the full financial year up to 31 December 2018 ("FY2018"), and is dedicated to providing information on economic, environmental and social performance that is material to KrisEnergy's business and key stakeholders. Further information on corporate governance, which is part of our sustainability, can be found under the section Corporate Governance on pages 34 to 47 of the 2018 Annual Report.

This report is set out on a "comply or explain" basis in accordance with Rule 711B and Practice Note 7.6 of the Mainboard Rules of the Singapore Exchange Securities Trading Limited ("SGX-ST"). KrisEnergy has chosen the Global Reporting Initiative ("GRI") framework as the most established international sustainability reporting standard and in respect of the extent to which such framework is applied, this report has been prepared in accordance with GRI Standards: Core Option.

We welcome feedback from all stakeholders. Please send all feedback to hinna.ijaz@krisenergy.com.

2018 Sustainability Report

Chairman Statement on Sustainability

Dear Stakeholders,

Despite the liquidity pressures we experienced throughout 2018, and continue to face in 2019, we have remained steadfast in our commitment to the principles on which our business is founded, namely a stimulating, transparent and a safety-oriented corporate culture, zero tolerance of bribery and corruption, diversity in the workplace and engagement and alignment with stakeholders, including our host governments and local communities.

One key action in 2018 was the introduction of human rights training for security contractors in Bangladesh. Unfortunately, there have been several security alerts in Bangladesh in recent years and it is necessary for us to employ security contractors at our main office in Dhaka as well as at the Bangora gas field operations in Block 9, which is approximately 50 kilometres to the east of the capital and surrounded by local communities. Security is always a major concern and we must ensure that the contracted parties have the requisite training to conform to KrisEnergy's internal policies and criteria in providing their services.

I am also pleased to note that we have expanded Health & Safety reporting in our sustainability framework. The GRI 403 standard covering Occupational Health and Safety was introduced in 2018 as a new reporting standard and we are able to deliver on five of the ten disclosures required:

- Disclosure 403-1: Occupational health and safety management system;
- Disclosure 403-2: Hazard identification, risk assessment and incident investigation;
- Disclosure 403-4: Worker participation, consultation and communication on occupational health and safety;
- Disclosure 403-5: Worker training on occupational health and safety; and
- Disclosure 403-9: Work-related injuries.

We will endeavour to expand our disclosures for the GRI 403 standard further in 2019.

It is important to emphasise that we have several "check" systems – both internal and external – to monitor performance and compliance to the many policies in place to ensure the health and safety of our employees, protection of the environment and continuity of operations.

Another concrete achievement in 2018 was the elimination of single-use plastic bottles in all KrisEnergy offices and operational sites. This has been a big step forward to reduce our waste and recycling and we will continue to monitor our recycling systems and look for areas where we are able to reduce waste and energy consumption.

Tan Ek Kia

Independent Non-Executive Chairman on behalf of the Board

1 April 2019

Our Approach to Sustainability

Reporting Principles

KrisEnergy has an internal Code of Conduct stipulating the Group's business principles and practices in our day-to-day activities. Our Code of Conduct provides a communicable and understandable framework for employees to observe the Group's principles of accountability, honesty and integrity in all aspects of our business and in our dealings with suppliers, contractors and other stakeholders working for or on behalf of KrisEnergy. We recognise that the involvement of our employees is key to the future success of the business and all employees are informed of, and can readily access, the Code of Conduct on our global intranet and company website, www.krisenergy.com. Our senior managers in each country are also responsible for ensuring that the principles set out in the Code of Conduct are communicated to and understood by all employees, and for ensuring compliance in their area of responsibility.

Our core values are:

- Openness;
- Respect;
- Integrity; and
- Professionalism.

Our Code of Conduct provides guidance on and emphasises our commitment to:

- Diversity and equality for all employees and stakeholders;
- Responsibilities whilst working for, with or on behalf of KrisEnergy;
- Fair and transparent employment practices;
- Environmental goals and initiatives;
- High standards in workplace health and safety standards and procedures;
- Community involvement throughout our operations;
- Whistle-blowing avenues in event of breach; and
- Safeguarding and proper use of the Company's information and assets.

In line with the Company's stance to pursue our business objectives with integrity and in compliance with applicable laws and regulations in all countries in which we operate, we also have the following corporate policies and guidelines in place, which are similarly available on our global intranet and are disseminated to our employees:

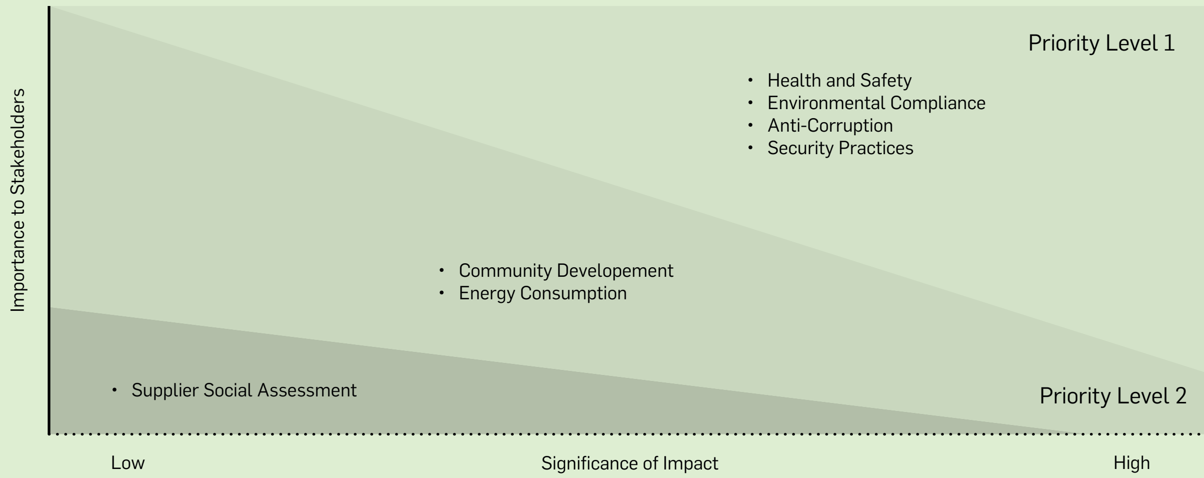
- Health & Safety Policy;
- Environmental Policy;
- Fire Safety Policy;
- Communications Policy;
- Corporate Social Responsibility Policy;
- Public Grievance Policy;
- Travel Policy;
- Drug & Alcohol Policy;
- Risk Management Policy;
- Whistle-blowing Policy;
- Policy to Prevent Improper Payments;
- Management Authority Approval Policy; and
- Enterprise Risk Management Framework.

Throughout our day-to-day activities, we are conscious of the needs of our employees, stakeholders, communities and the environment. Professionalism, high ethical standards, accountability to stakeholders, respect for law, people-driven, encouraging community involvement and striving for excellence are the key principles on which our daily business practice is based.

Reporting Process

Report Content and Topic Boundaries

We applied the Principle of Materiality to identify and prioritise sustainability topics for inclusion in this report. In addition, our economic, environmental and social impacts and the substantive expectations and interests of our stakeholders were taken into account. For 2018, we included a new material topic to address human rights' principles in our security practices. We also expanded on Health & Safety reporting to align with new GRI 2018 reporting standards. The chart below reflects our material topics and rankings.



An executive meeting determined the key topics for this report and was attended by Senior Management and representatives from key departments. A definitive meeting was subsequently held with the Board of Directors to finalise the key material topics to be disclosed.

The table below highlights the topic boundaries to our entities.

POTENTIAL ISSUE CLUSTERING AND RATING

	Anti-Corruption	Energy	Environmental Compliance	Health and Safety	Security Practices	Local Community Engagement	Supplier Management
Singapore Office	V	V	V	V			
Indonesia Office	V	V	V	V			V
Vietnam Office	V	V	V	V			
Cambodia Office	V	V	V	V		V	
Thailand Office	V	V	V	V		V	V
Bangladesh Office	V	V	V	V	V	V	V
Wassana Ops	V	V	V	V		V	V
Bangora/ Gopalnagar Ops	V	V	V	V	V	V	V

NOTES

Injury classification is reported in all KrisEnergy entities, but the focus of this injury classification will be on KrisEnergy-supervised operations, namely the Wassana oil field in the Gulf of Thailand and the Bangora/Gopalnagar gas field onshore in Bangladesh, for the material topic on work-related injuries, disclosure 403-9.

Our Corporate Governance

The KrisEnergy Group is committed to maintaining a high standard of corporate governance, and to complying with the principles of the Code of Corporate Governance issued by the Monetary Authority of Singapore.

The composition of our board is an important aspect of our approach to corporate governance. Our board comprises seven members, including five independent directors, who exercise objective judgement in our corporate affairs. In this regard, the board has reviewed and identified key material environmental, social and governance factors relating to KrisEnergy. Further, our Independent Non-executive Chairman and our Chief Executive Officer are responsible for overseeing all aspects of our business, including our commitments to sustainability, and are supported by a strategic team of general managers. For more information, please refer to the Corporate Governance section on pages 34-47 of the 2018 Annual Report.

Anti-corruption

The KrisEnergy Group, with our operations across different geographies and our engagement with numerous contractors, consultants, suppliers, joint-venture participants and agents, has multiple vulnerable points which may expose us to risks of corruption. Preventing and managing risks associated with corrupt practices across KrisEnergy's operations is a key concern to our stakeholders.

We manage these risks through maintaining our commitment to high standards of ethical behaviour and actively ensuring that the Group's zero-tolerance policy towards corruption, bribery and unethical actions is strictly observed. Our core approach is to enable all personnel to make informed business choices that avoid all forms of breach and thereby protect the value of our business.

To ensure and achieve our objectives, we constantly reinforce our Policy to Prevent Improper Payments which requires all KrisEnergy personnel, regardless of their citizenship, residence, or the jurisdiction in which they are working, to comply with applicable anti-corruption laws, such as the *U.S. Foreign Corrupt Practices Act of 1977* and the *U.K. Bribery Act of 2010*.

For instance, in relation to third-party contracting procedures, our policy requirements mandate that standard written representations and warranties on non-corruption are included in third-party contracts, and that we use commercially reasonable efforts to ensure that our policy principles are incorporated in joint-venture/operating agreements. In conjunction with this, we have in place questionnaires to ensure due diligence in respect of our third-party contracts. We also maintain an internal register documenting all gifts given or received, entertainment, sponsorships and charitable contributions, which is reported to the Audit and Risk Management Committee on a quarterly basis. In relation to KrisEnergy employees, all employees across the Group are required to complete and sign a compulsory certificate of compliance annually, to acknowledge that they are aware of, have read, and are in compliance with our Policy to Prevent Improper Payments. Similar certificates of compliance are also sought periodically from all third-party intermediaries.

Our Whistle-blowing Policy also underpins our anti-corruption commitment in enabling employees to, in confidence, raise concerns internally and disclose any impropriety at a high level and through well-defined and accessible channels. We have in place arrangements for independent investigation and appropriate follow-up actions where necessary.

In addition to the certification of compliance required annually, our policies are communicated to employees in all regions and uploaded onto our global intranet for ready access. Every KrisEnergy employee is thus informed of our policies and practices. To supplement this, we organise and conduct regular anti-bribery and corruption training sessions at our major offices and work locations to refresh and update employees, where there are opportunities for question and answer sessions and one-on-one discussions. Our most recent training session during this reporting cycle was conducted in our Vietnam office and was attended by present employees including governance body members.

Senior managers in each country in which we operate also ensure that adequate controls are in place to prevent improper payments and manage the standards we have set out. Our General Counsel has also completed at least eight hours of formal anti-corruption education annually and acts as a compliance officer in supervising and ensuring that our personnel understand and are in full compliance with our Policy to Prevent Improper Payments and applicable law. Our internal auditors inspect and ensure that all financial transactions are properly and fairly recorded in our books of accounts and our external auditors have the authority and instruction to test expenditures in the course of normal audit activities to evaluate whether payments in the samples tested are potentially improper payments.

No incidents of bribery or corruption were identified in 2018. It is KrisEnergy's continued goal to maintain zero incidents of bribery and corruption.

Our People

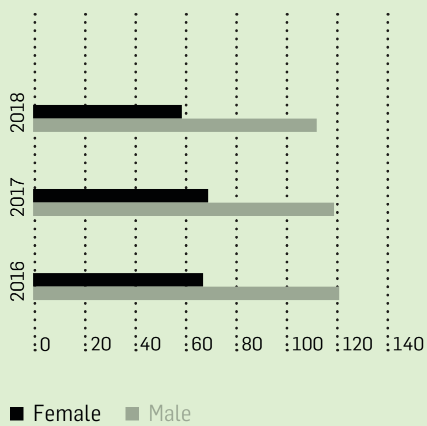
KrisEnergy has established offices in Bangladesh, Cambodia, Indonesia, Singapore, Thailand and Vietnam. It also has field operations onshore in Bangladesh and offshore in the Gulf of Thailand.

Our internal philosophy is that all personnel, either directly or indirectly employed, play a vital role in our success and we adopt a zero-tolerance policy for any discrimination within the workplace. We engage with our people in each of the countries where we operate, and we ensure their wellbeing is our top priority. Our goal is to create a diversified workforce in which everyone is given an equal opportunity in a transparent environment that promotes empowerment and fulfilment.

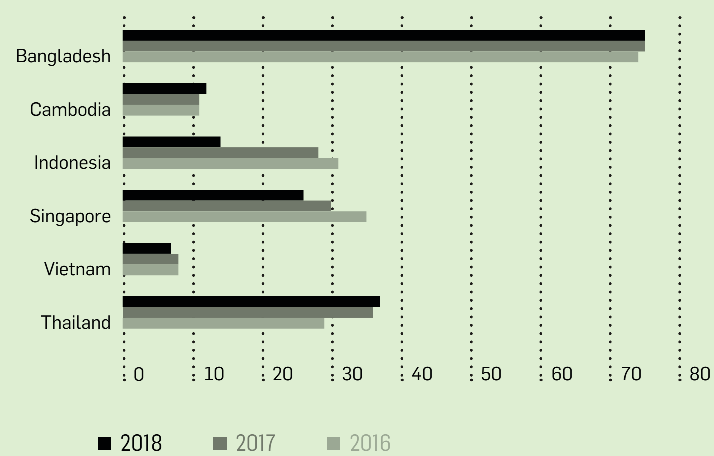
Our employees are not covered by collective bargaining agreements but have the right to exercise freedom of association.

KrisEnergy employed 459 people in 2018. Permanent employees represented 37% of the total headcount. We contract largely third-party personnel for our operational sites, which require a multitude of different skillsets on a 24/7 rotational basis. The numbers reflected in the charts below for the past three years were collated from each country's administrative records. Our approach is to offer remuneration based on experience and merit without reference to gender. The ratio of female to male employees is relatively equal throughout the Company with the exception of the Dhaka office and the field operations' site in Bangladesh where patriarchy remains relatively strong within the nation and a high percentage of the workforce are male.

Total Numbers of Employees by Gender



Total Number of Employees by Region



Occupational Health & Safety

Health & Safety are embedded in KrisEnergy's culture and across the entire organisation. We have established a robust internal Environmental, Health & Safety Management System ("EHSMS") that is implemented according to the *International Organisation for Standardisation* ("ISO") 45001, 14001 and *Occupational Health and Safety Assessment Series* ("OHSAS") 18001, overseen by SGS International Certifications Services ("SGS"). The EHSMS is established in Bangladesh, Singapore and Thailand. Current staffing levels in Cambodia, Indonesia and Vietnam fall below thresholds to reasonably have the capacity to establish an EHSMS. However, with existing systems and procedures in place, certifying these offices can be undertaken with ease.

One consideration of the EHSMS covers medical and travel security services and we contract International SOS ("ISOS") to provide our staff and directly employed contractors access to expert medical and travel security advice. Additionally, offshore employees and contractors have access to 24/7 mobilisation of medical assistance and evacuation.

Our Singapore and Dhaka offices and onshore Bangladesh field operations have renewed OHSAS 18001/ISO 45001 certifications accredited by the Joint Accreditation System of Australia and New Zealand ("JAS-ANZ")/Swiss Accreditation Service ("SAS"). We intend to incorporate the current EHSMS into our other entities once their activities and operations evolve to an optimal level.

A critical section of the EHSMS includes hazard identification, risk management and incident investigation. Our internal online reporting and measurement portal enables monitoring of performance regarding risks and incidents and provides valuable information for areas of improvement. Risk Management Policy, EHSS Manual, Health & Safety Policy and the EHSMS hazard and effects procedures are drivers for risk management and assessment within the organisation. Our staff are fully trained in conducting risk assessments for routine and non-routine work. We have a Permit-to-Work ("PTW") system to handle operating risks both offshore and onshore. Job Safety Analysis is also conducted for moderate to high risk tasks.

Our risk management assessment is a four-stage process: identifying hazards; assessing risks; implementing controls; and monitoring the overall risk management procedure.

Identification of hazards allows us to establish the scope and context of the assessment and its boundaries. Identification or spotting risks in the workplace is highly advocated amongst staff. Staff are encouraged to report hazards via hazard report cards or anonymously via the online portal. We do not penalise staff for the reporting of risks. In the Hazard and Effects Management procedure, staff have the right to stop work immediately where is concern of a risk of injury or ill-health.

Risk assessment via an internal risk matrix based on the *ISO Petroleum and Natural Gas Industries – Offshore Production Installations – major accident hazard management during the design of new installations ("ISO 17776-2016")* provides a structured review technique alongside professional judgement and experience. Staff directly involved in a risk activity are usually involved in the risk assessment process. For safety risks, KrisEnergy adopts the "as low as reasonably practicable" principle whereby residual risk shall be reduced as far as reasonably practicable.

Identified risks are evaluated and mitigation steps implemented according to six levels of control measures: elimination, substitution, isolation, engineering controls, administration controls and the use of personal protective equipment. We endeavour to eliminate risk as far as reasonably practicable. The results of the risk assessment are evaluated and discussed with more widely, for example, daily tool-box talks are conducted on site before an operational risk activity is started.

Lastly, risks and risk assessments are reviewed and monitored regularly to ensure that risk identification and assessment remain appropriate. Checks are in place for the continued effectiveness of risk controls and are measured against defined performance standards. We intend to increase the frequency of our incident and risk reporting on the online reporting system for all our operated blocks.

Training is a serious and necessary part of our business activities to ensure competency and avoid the risk of injury. We periodically provide a range of operational training schedules, such as safety and technical courses, among others. We regularly carry out various in-house training and emergency response drills to ensure all employees remain vigilant and uphold best practice in the industry. All workers on field locations are trained prior to arrival onsite. Their training needs are assessed according to work-related activities. A training matrix is drawn up to identify the necessary skills required for each job to be performed and any training gaps. In addition, for the Bangladesh onshore operations, there are competency profiles established for all staff. Each person's competency and capabilities are evaluated through the system and gaps are identified before the necessary training is prescribed. We intend to enhance the training matrix within operations to evaluate effectiveness.

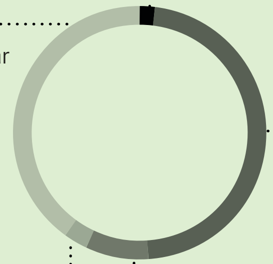
We have established Safety Committee groups in all OHSAS 18001/ISO 45001 certified offices and operations. The groups comprise management and employees and are tasked to review policies, procedures and practices relating to occupational health and safety. They are also drivers of quarterly or monthly Environmental, Health, Safety & Security ("EHSS") initiatives within the company to address employees' concerns or increase awareness over EHSS matters. Our aim is to increase workers' representation by ensuring that all operating locations establish Safety Committee groups.

In addition, we ensure compliance with all our EHSS policies throughout our offices and operations and this can range from internal audits conducted by our management teams, individually by the Safety Committee groups, externally by SGS or through routine and frequent PTW audits. An example of compliance with our Drug & Alcohol policy would be where every personnel undergo breathalyser tests before heading offshore to our G10/48 Wassana site.

A G10/48 offshore personnel undergoing a breathalyser test

Between January and December 2018, the KrisEnergy Group recorded 1,614,865 man-hours at operation locations assets with one Loss Time Injury ("LTI").

Total Man Hours



It is standard internal procedure that following the occurrence of an LTI incident in a KrisEnergy-operated field operation, a thorough investigation is conducted and addressed through root cause analysis, with corrective and preventive actions implemented thereafter. Our philosophy is continual improvement. Our ongoing target for all operations is to work on the identification and mitigation of risks and hazards to prevent incidents and recurrence.

One LTI on Offshore G10/48 Wassana Oil Platform, Gulf of Thailand:

22 March 2018

- Work on a thrust block replacement on a pump was conducted by three workers.
- Pump was isolated but passing isolation valve contained pressure.
- When one worker was locating the thrust block, he was trying to line up the holes with the shaft coupling when the shaft sprung out of the pump barrel causing his left little finger tip to be crushed between thrust block and motor.
- Medivac was quickly initiated, and the injured party's injury was stabilised immediately.

After thorough investigations were conducted, it was deduced that a lack of isolation of the pump was the main cause of the incident. As a result, the following measures are now in place to prevent such an incident from recurrence:

- A standing instruction that no work will take place on a pump without 100% positive isolation.
- Complete review on our isolation procedure was undertaken and several changes were made accordingly. This included new design of an isolation and Hazard & Operability Study before a change is conducted.
- Re-training of staff on these procedures was conducted immediately.

KrisEnergy recorded zero fatalities during 2018. The injury classifications below include our operational sites in Thailand and Bangladesh. Our Total Recordable Injury Frequency Rate ("TRIFR") includes LTIs, Restricted Work Day Cases ("RWDC"), Medical Treatment Cases ("MTC") as well as First Aid Cases ("FAC").

YEAR	LOST TIME INJURY FREQUENCY RATE ("LTIFR")	TOTAL RECORDABLE INJURY FREQUENCY RATE
2018	0.62	0.74
2017	0	0.38
2016	0	1.67

TRIFR rose in 2018 as a result of higher drilling activity in Thailand.

External initiatives

KrisEnergy supports and is committed to a few national and international economic, environmental and social principles, codes and frameworks. Some of these include the GRI Standards, the OHSAS 18001/ISO 45001 certification standards and the ISO 14001 standards. We continue to review suitable initiatives to enhance the sustainable development of our business.

Our Environment

Our Approach

Although oil and gas are extracted from the Earth's subsurface, there is an operational footprint at surface level. We are cognisant of the impact of our operations on the environment and the communities in the areas surrounding field locations and operational sites. We endeavour to reduce our impact and protect the environment and we apply across our organisation the precautionary approach under the *United Nations Rio Declaration 1992, Principle 15*. We ensure that before proceeding with any operation, an Environmental Impact Assessment ("EIA") is conducted to identify the risks associated with the operation and assess the mitigation measures to be implemented.

For 2018, KrisEnergy recorded zero non-compliance with environmental laws and/or regulations across the Group. In alignment with both ISO 14001 and the regulatory requirements in each country of operation, KrisEnergy has an integrated Group-wide system for the reporting of spillages such as oil, dirty water and other pollutants.

We have established a Group-wide Environmental Management System, which complies with ISO 14001 international standards. Our Singapore and Dhaka offices and the Bangora field operation are all ISO 14001 certified by SGS and accredited by UK Accreditation Service ("UKAS")/SAS.

All KrisEnergy offices and operations practice the three R's: reduce, reuse and recycle. As an ISO 14001 compliant company, waste management is one of the vital sections of environmental management. For KrisEnergy operations, waste is recycled, segregated and/disposed of in compliance with international guidelines and national laws, all of which are stipulated in our waste management plans.

Even though the environmental impact of our office activities is relatively immaterial, we have recycling systems in place with designated recycling bins placed strategically within the office premises. KrisEnergy works with building management to comply with their recycling requirements.

In 2018, in a Group-wide initiative, all KrisEnergy offices and field locations ceased using single-use plastic water bottles. Drinking water is now sourced from filtration systems and/or water dispenser tanks. This has eliminated the Group's plastic waste from water bottles.

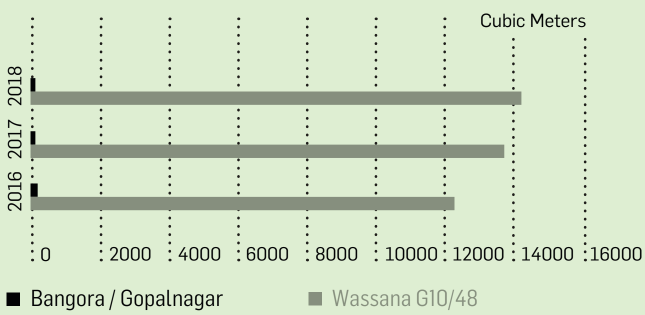
Energy

In line with the ISO 14001 international standard for energy consumption, we continuously monitor our energy usage in all our operations and offices. We aim to be energy efficient and encourage staff to be aware of energy use and to participate in steps to reduce consumption by utilising energy saving tips in their daily work. Educational quizzes and videos have been circulated to garner interaction; additional LED lights have been installed within offices; and equipment not in use is switched off over weekends. KrisEnergy aims to maintain its electricity consumption numbers at current levels.

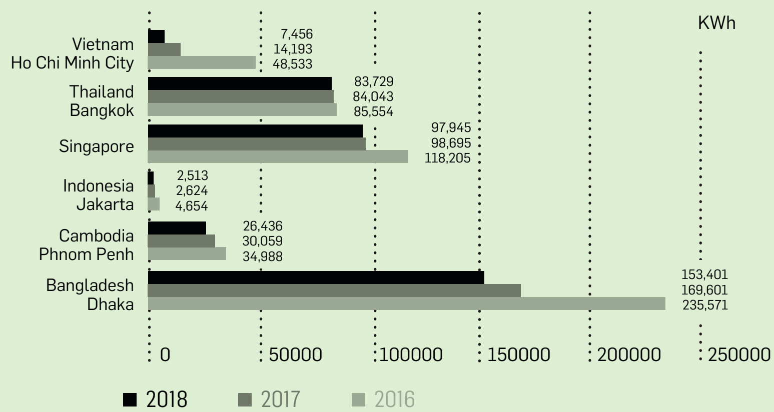
Electricity is the main source of energy consumption in KrisEnergy's offices, but operational sites rely on diesel generators for power. The charts below provide a breakdown of energy (electricity/diesel/gas) consumption in KrisEnergy's offices, the Gumti and Gopalnagar Bangora field locations onshore Bangladesh, and in the Wassana oil field in the Gulf of Thailand.

Diesel Consumption

Diesel consumption in our Wassana G10/48 offshore operation increased slightly in 2018 due to exploration and infill drilling in 1Q2018 and 4Q2018

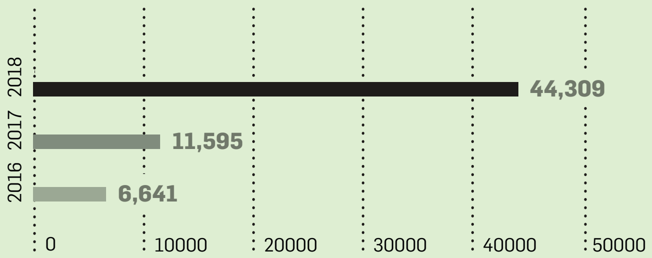


Electricity Consumption: Office

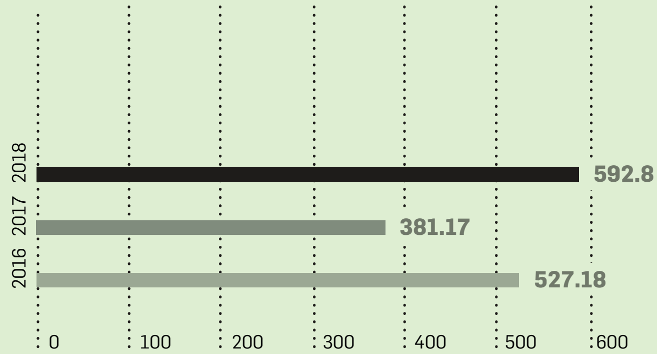


Electricity Consumption: Gumti and Gopalnagar (KWh)

Electricity consumption in Gumti increased significantly in 2018 as Gopalnagar's records were included whereas 2016 to 2017 were based solely on Gumti's records.



Gas Consumption : Bangora (mmcf)



Our Stakeholders

As part of the materiality assessment process, KrisEnergy identified six key stakeholder groups to engage, based on their level of influence and impact on our activities.

STAKEHOLDERS	HOW WE ENGAGE	KEY TOPICS RAISED
Investors/ Shareholders	Annual meetings Half-yearly investor forums	Corporate governance Financial performance Business outlook
Employees	Quarterly or half yearly EHSS initiatives Town hall meetings Daily/weekly safety meetings	Company's outlook Employees' welfare Operational personnel
Contractors/ Suppliers	Contractor/supplier management & assessments	EHSS standards, Supplier Code of Conduct Terms & agreements for contracted work
Local Community	Community programs in areas where we operate as well as the cities we have offices Public participation	Education, women empowerment, social development, health-care and financial support to the local community Seismic/drilling/production operations awareness
Regulators	Regular scheduled meetings with government authorities (i.e., Department of Mineral Fuels, SKKMigas, PetroBangla, PetroVietnam, Cambodian Ministry of Mines and Energy)	Compliances/ environmental/EHSS reporting personnel/sourcing and training local talent
Joint-Venture Partners	Operational Committee Meetings & Technical Committee Meetings	Operational, financial, technical, joint operations & EHSS matters

As part of KrisEnergy's engagement with the wider upstream industry as well as legal, financial and safety institutions, we subscribe to the following associations and organisations:

- ISOS
- Oil Industry Environmental Safety Group Association
- Oil Spill Response Limited
- South East Asia Petroleum Exploration Society
- Indonesian Petroleum Association
- Society of Petroleum Engineers
- Association of International Petroleum Negotiators
- Chartered Accountants Australia & New Zealand
- Chartered Public Accountant Canada
- Institute of Singapore Chartered Accountants
- Association of Chartered Certified Accountants
- Chartered Financial Analyst Institute
- International Business Chamber Cambodia
- Extractive Industry Governance Forum

Security Practices

We take the safety and security of our people and assets seriously and in countries where additional security is required, we strive to make it readily available. KrisEnergy does not employ security personnel within the organisation. We contract third-party organisations to provide trained security forces only for the Dhaka office and the onshore Bangora field operation, both in Bangladesh, where internal domestic security risks are higher than for other operations. In addition to compulsory training and drills such as, but not limited to, security, self-defence, vehicle and search procedures, fire-fighting and first-aid; we require starting in 2018, that our contractors provide basic human rights training to their employees working at KrisEnergy-operated site locations. To date 100% of contracted security personnel are trained under the Voluntary Principles on Security and Human Rights.

The basic human rights training includes an overview of the basic rights and freedoms to be provided so that everyone is treated fairly and with dignity, equality and respect. The role of security personnel deployed in KrisEnergy operations is highlighted along with the Code of Conduct. Conflict resolution is also discussed. Training on a monthly basis is conducted onsite field operations by the contractor's managers, which is reinforced by additional sessions every two months by instructors from Dhaka.

We intend to ensure that contracted security personnel uphold a high standard of appropriate conduct to third parties, particularly regarding the use of force to prevent human-rights' abuses or mishandling of employees, contractors and the local community. Our target is to ensure full training and compliance of the *Voluntary Principles on Security and Human Rights* met by our contractors and their employees.

Local Communities

The upstream oil and gas industry has a multitude of inherent risks and has the potential to impact local communities close to our operational sites. As such, we ensure full engagement with communities regarding all our events and operations. Their well-being and livelihood are part of our daily concerns and assessments to ensure our impact is positive and sustainable. In 2018, KrisEnergy implemented a public grievance policy within the organisation to provide a mechanism to raise our engagement with communities. Various pathways for the public to provide feedback have been established and communicated to the relevant stakeholders.

Additionally, we embark on public participation, consultation and engagement before we conduct any operational activity be it onshore or offshore. We believe such forums and educational sessions are essential to communicate and provide technical substance and EHSS measures to stakeholders including local communities, local authorities, governments, shareholders, debt holders, partners and service providers.

KrisEnergy is intending to undertake in 2019 a 1,200 sq. km 3D seismic acquisition program in the Cambodia Block A licence area in the Gulf of Thailand. In preparation for the survey, we held a series of public meetings for various stakeholders such as local fishermen and communities in the Preah Sihanouk, Kampot and Koh Kong provinces, to explain details, the program's methodology, equipment required, timeline and respond to any enquiries.

Public Participation conducted on 6 March 2018 in Preah Sihanouk

Corporate Social Responsibility ("CSR")

Our CSR projects target sustainability where our intended impact is to provide communities platforms to continue programs without aid in the longer term. We focus our CSR endeavours on education, healthcare and social development - specifically women's economic empowerment. We contribute to various educational programs and charities focusing on the needs and progression of children and women. We believe that education is an empowerment tool allowing everyone to contribute to the growth of the entire community and for future generations to come.

We distribute scholarships across our project areas to underprivileged meritorious students and we work with various Non-governmental Organisations ("NGOs") that support students through the enhancement of the quality of education, materials and learning environment.

In 2018, we selected four high schools in the districts of Steunghav and Prey Nub in the coastal province of Sihanoukville, southwest Cambodia, which is the location of our future land-based operations. Working together with the schools, we identified areas for improvement in the educational programs as well as facilities. During a site visit, we came to understand that English language lessons were of low standard and frequency and only pupils from wealthier backgrounds were able to attend the private tuition necessary to improve. With KrisEnergy's support, the English curriculum was upgraded, and additional classes have been added into timetables. In addition, KrisEnergy funded scholarships to deserving, underprivileged students, many of whom were unable to afford basic school fees and books and were at risk of dropping out, and provided books for the school libraries.

English class in session in Cambodia

Under our social development goals, we continue support of the Strengthening Women Entrepreneurs ("SWE") program, which assists women who work in local self-help groups, or Women Empowerment Groups ("WEGs") in Sihanoukville, Cambodia. We reinforce training for WEGs in accounting and business planning, we help connect them with several local and larger business markets, and through a monitoring procedure, we ensure that the WEGs are meeting regularly and participating in their district saving schemes. Together with several female community leaders, we advise ongoing WEG businesses to help keep them on a successful path. In addition, we organise an achievement session at the end of each year where members who have performed exceptionally in their business share their experiences and successes. We engage local authorities to attend the achievement sessions to recognise and share in the progress of the community.

Refresher training on village bank management and accounting system conducted by KrisEnergy for the WEGs

Award session in Preah Sihanouk Province for the SWE Project on 13 December 2018

In 2018, we have a total of 19 WEGs and 362 women participating, who together, have accumulated total savings of US$169,448.

The lack of adequate and sanitary healthcare is an ongoing crisis in many parts of the world including Asia. We work with several NGOs in Bangladesh to continue with either existing or new healthcare camps in our local communities. In 2018, we conducted in partnership with Young Power in Social Action a free healthcare camp for mothers and their children in three locations: Bangora, Gopalnagar and Gumti. The main objectives were to support women, and specifically pregnant women, to raise awareness on maternal and child health issues. Activities included a free health check-up for mothers and children, distribution of supplements and vitamins, talks on immunisation, safe drinking water, personal hygiene and sanitation, and nutrition and healthcare practices.

Mother and child healthcare camp session

Sanitation is also a concern in schools, especially in rural areas in Bangladesh. KrisEnergy has contributed to build female latrines in schools in the Bangora field production area where toilet facilities are often co-ed, which deters many female students from attending classes.

With increasing focus on mental health awareness worldwide, we partnered with Innovation for Wellbeing Foundation to provide mental health training first aid to school teachers in schools located near the onshore gas plant in Bangladesh. The teach-in for teachers provided tools to identify students with potential mental health issues and to handle sensitive situations. Our goals are to reduce the stigma associated with mental health issues and promote early intervention to enable recovery starting with caretakers, i.e. parents, teachers and schools. We believe the engagement of local communities and addressing issues via education and health camps will lead to improvements in quality of life.

Our CSR monitoring programs gather feedback to determine areas for improvement. We monitor trends, measure changes and capture knowledge to improve performance and increase transparency. Our monitoring attempts to ensure the sustainability of the programs in the long term and the impacts on those in the communities. We intend to continue our current projects for the upcoming year.

Our Supply Chain

Our supply chain includes our administrative and operational businesses where we collaborate with local and foreign suppliers. We are bound by government regulations in the countries in which we operate, to undertake tender processes for certain works and services where multiple bids are received and assessed before a final award is made based on commercial, technical and social criteria. This process increases competitiveness and transparency for both the company and government.

Our offices in Bangladesh, Singapore and Thailand have established procurement teams who deal with contractors, suppliers and service providers for our operations. This may range from refurbishment of vessels and contracting of drilling rigs and services to hiring of seismic acquisition providers and third-party independent environmental surveyors. From our administrative offices, we engage with companies that provide, amongst others, oil spill capabilities and EHSS assessments. It is our intention to contract local resources as long as all necessary EHSS conditions and appropriate training requirements are fulfilled.

Our approach is to source products/materials and services responsibly from suppliers, vendors and contractors where the provider is committed to the Company's ethics and Code of Conduct. As a general practice, we ensure that there is a minimum of three bidders for any project and all bidders must go through our vendor approval process.

We work with our suppliers and contractors throughout the lifecycle of a project. During a pre-qualification process, suppliers are required to complete an assessment for their EHSS and social criteria. We analyse their track record, EHSS and labour criteria and any certifications in key sustainable areas. This may range from OHSAS 18001/ISO 45001 and ISO 14001 certifications or any other accreditations of equivalent value. Additionally, our Supplier Code of Conduct as well as relevant EHSS standards and policies are provided at this stage.

EHSS is regarded as the top priority within KrisEnergy and therefore we engage with contractors and providers with a similar ethos. During the contracted period of activity, bridging documents are established to merge KrisEnergy's and the contractor's EHSS requirements. Contractors are expected to follow KrisEnergy's EHSS policies, procedures and standards. We regularly monitor suppliers' performance to ensure compliance to KrisEnergy's standards. We will continue to effect due diligence and incorporate our existing Supplier Code of Conduct in all new agreements with suppliers.

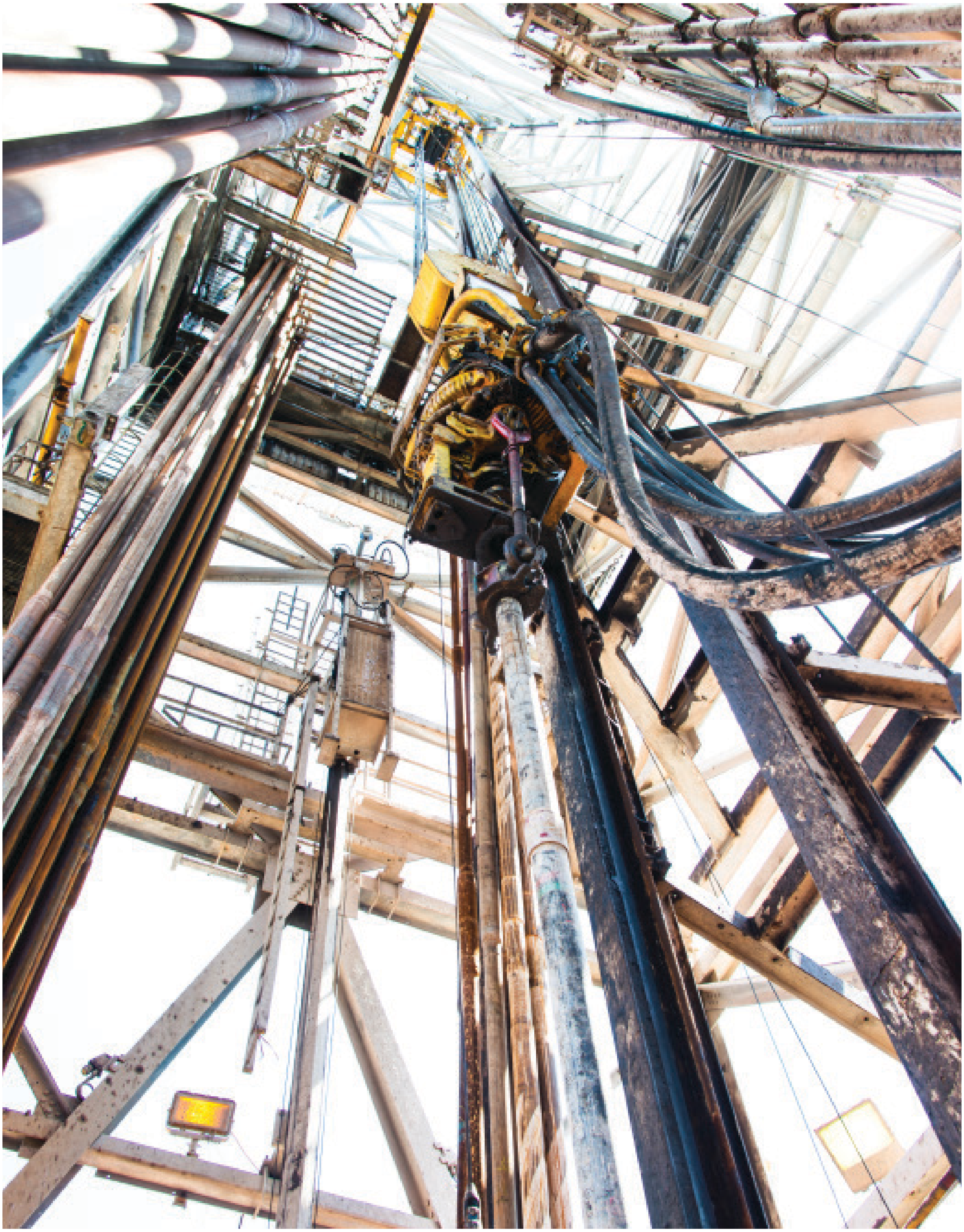
GLOSSARY

CSR	Corporate Social Responsibility.
EHSMS	Environmental, Health and Safety Management Systems.
EHSS	Environmental, Health, Safety and Security.
EIA	Environmental Impact Assessment.
FAC	First Aid Cases.
FY2018	Full financial year up to 31 December 2018.
GRI	Global Reporting Initiative.
ISO 14001	An international environmental management system standard certified by SGS International Certifications Services and accredited by the SAS or UKAS.
ISO 17776-2016	ISO Petroleum and Natural Gas Industries – Offshore Production Installations – major accident hazard management during the design of new installations.
ISO 45001/OHSAS 18001	An international occupational health and safety management system standard overseen by SGS International Certifications Services and accredited by the SAS or JAS-ANZ.
ISOS	International SOS
JAS-ANZ	Joint Accreditation System of Australia and New Zealand
LTIFR	Lost Time Injury Frequency Rate. The number of lost time injuries per 1,000,000 hours worked.
LTI(s)	Loss time injury (injuries).
MTC	Medical Treatment Cases.
NGO	Non-governmental organisation.
PTW	Permit-to-Work
RWDC	Restricted Work Day Cases.
SAS	Swiss Accreditation Service.
SGS	SGS International Certifications Services.
SGX-ST	Singapore Exchange Securities Trading Limited.
SWE	Strengthening Women Entrepreneurs.
TRIFR	Total Recordable Injury Frequency Rate. The number of recordable injuries per 200,000 hours worked
UKAS	UK Accreditation Service.
WEG	Women's Empowerment Group.

GRI Content Index

GRI STANDARD	DISCLOSURE	PAGE NUMBER(S) AND/OR URL(S)
GRI 101: Foundation 2016		
General Disclosures		
GRI 102: General Disclosures 2016	**Organizational Profile**	
	102-1 Name of the Organization	Front Cover
	102-2 Activities, brands, products and services	Page 2, 4-5
	102-3 Location of headquarters	Page 4-5, 150
	102-4 Location of operations	Page 4-5, 12-17, 150
	102-5 Ownership and legal form	Page 23-33, 102-103
	102-6 Markets served	Page 4-5, 8
	102-7 Scale of the organization	Page 2, 26-30, 32-33, 102-103, 150
	102-8 Information on employees and other workers	Page 4, 132
	102-9 Supply chain	Page 139
	102-10 Significant changes to the organization and its supply chain	None
	102-11 Precautionary Principle or approach	Page 135
	102-12 External initiatives	Page 135
	102-13 Membership of associations	Page 136
	Strategy	
	102-14 Statement from senior decision-maker	Page 128
	Ethics and Integrity	
	102-16 Values, principles, standards, and norms of behaviour	Page 129-130
	Governance	
	102-18 Governance structure	Page 34-47, 130
	Stakeholder Engagement	
	102-40 List of stakeholder group	Page 136
	102-41 Collective bargaining agreements	Page 132
	102-42 Identifying and selecting stakeholders	Page 136
	102-43 Approach to stakeholder engagement	Page 136
	102-44 Key topics and concerns raised	Page 136
	Reporting Practice	
	102-45 Entities included in the consolidated financial statements	Page 32-33, 64
	102-46 Defining report content and topic Boundaries	Page 130
	102-47 List of material topics	Page 130
	102-48 Restatements of information	None
	102-49 Changes in reporting	None
	102-50 Reporting period	Front Cover
	102-51 Date of most recent report	1 April 2018
	102-52 Reporting cycle	Page 127
	102-53 Contact point for questions regarding the report	Page 127
	102-54 Claims of reporting in accordance with the GRI Standards	Page 127
	102-55 GRI content index	Page 140
	102-56 External assurance	None
MATERIAL TOPICS		
GRI 200 Economic Standard Series		
ANTI -CORRUPTION		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 131
	103-2 The management approach and its components	Page 131
	103-3 Evaluation of the management approach	Page 131
GRI 205: Anti-corruption 2016	205-2 Communication and training about anti-corruption policies and procedures	Page 131
	205-3 Confirmed incidents of corruption and action taken	Page 131
GRI 300 Environmental Standards Series		
ENERGY		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 135
	103-2 The management approach and its components	Page 135
	103-3 Evaluation of the management approach	Page 135
GRI 302: Energy 2016	302-1 Energy consumption within the organization	Page 135 and 136
ENVIRONMENTAL COMPLIANCE		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 135
	103-2 The management approach and its components	Page 135
	103-3 Evaluation of the management approach	Page 135
GRI 307: Environmental Compliance 2016	307-1 Non-compliance with environmental laws and regulations	Page 135
GRI 400 Social Standards Series		
OCCUPATIONAL HEALTH AND SAFETY		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 133, 134 and 135
	103-2 The management approach and its components	Page 133, 134 and 135
	103-3 Evaluation of the management approach	Page 133, 134 and 135
GRI 403: Occupational Health and Safety 2018	403-1 Occupational health and safety management system	Page 133
	403-2 Hazard identification, risk assessment, and incident investigation	Page 133
	403-4 Worker participation, consultation and communication on occupational health and safety	Page 133
	403-5 Worker training on occupational health and safety	Page 133
	403-9 Work-related injuries	Page 134 and 135
SECURITY PRACTICES		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 136
	103-2 The management approach and its components	Page 136
	103-3 Evaluation of the management approach	Page 136
GRI 410: Security Practices 2016	410-1 Security personnel trained in human rights policies or procedures	Page 136
LOCAL COMMUNITIES		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 137, 138 and 139
	103-2 The management approach and its components	Page 137, 138 and 139
	103-3 Evaluation of the management approach	Page 137, 138 and 139
GRI 413: Local Communities 2016	413-1 Operations with local community engagement, impact assessments and development programs	Page 137, 138 and 139
SUPPLIER SOCIAL ASSESSMENT		
GRI 103: Management Approach 2016	103-1 Explanation of the material topic and its Boundary	Page 139
	103-2 The management approach and its components	Page 139
	103-3 Evaluation of the management approach	Page 139
GRI 414: Supplier Social Assessment 2016	414-1 New suppliers that were screened using social criteria	Page 139

Notice of Annual General Meeting



Notice of Annual General Meeting

KrisEnergy Ltd.

Company Registration Number: 231666 | Incorporated in the Cayman Islands on 5 October 2009

NOTICE IS HEREBY GIVEN THAT THE SIXTH ANNUAL GENERAL MEETING OF KRISENERGY LTD. (THE "COMPANY") WILL BE HELD AT CINNAMON ROOM, LEVEL 5, NOVOTEL CLARKE QUAY SINGAPORE, 177A RIVER VALLEY ROAD, SINGAPORE 179031 ON 26 APRIL 2019 AT 9.00 A.M. TO TRANSACT THE FOLLOWING BUSINESS (THE "ANNUAL GENERAL MEETING"):

A	Ordinary Business	Ordinary Resolution
1	To receive and adopt the Directors' Report and the Audited Financial Statements for the financial year ended 31 December 2018 and the Auditor's Report thereon.	Resolution 1
2	To re-elect Mr. Tan Ek Kia, a Director retiring pursuant to Article 125 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory note 1]	Resolution 2
3	To re-elect Mr. Duane Carl Radtke, a Director retiring pursuant to Article 125 of the Company's Articles of Association, and who, being eligible, offers himself for re-election as a Director of the Company. [See Explanatory note 1]	Resolution 3
4	To approve the sum of US$592,500 (S$814,658) to be paid to all non-executive directors as Directors' fees for the financial year ended 31 December 2018. (2017: US$600,000 (S$807,366)) [See Explanatory note 2]	Resolution 4
5	To re-appoint Deloitte & Touche LLP as Auditors of the Company and to authorise the Directors to fix their remuneration.	Resolution 5

B **Special Business** **Ordinary Resolution**

To consider and, if thought fit, to pass the following resolutions as Ordinary Resolutions, with or without modifications:

6 Authority to issue shares — Resolution 6

That pursuant to Rule 806 of the Listing Manual of the Singapore Exchange Securities Trading Limited ("SGX-ST"), authority be and is hereby given to the Directors of the Company to:

(1) (i) issue shares in the capital of the Company (the "Shares") (whether by way of rights, bonus or otherwise); and/or

(ii) make or grant offers, agreements or options that might or would require Shares to be issued, including but not limited to the creation and issue of (as well as adjustments to) warrants, debentures or other instruments convertible into Shares (collectively, "instruments"), at any time and upon such terms and conditions and for such purposes and to such person(s) as the Directors may in their absolute discretion deem fit; and

(2) (notwithstanding the authority conferred by this Resolution may have ceased to be in force) issue shares in pursuance of any Instrument made or granted by the Directors while this Resolution was in force, provided that:

(a) the aggregate number of Shares to be issued pursuant to this Resolution (including new Shares to be issued in pursuance of Instruments made or granted pursuant to this Resolution) shall not exceed 50.0 per cent. of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below), of which the aggregate number of Shares to be issued other than on a pro rata basis to the shareholders of the company (including new shares to be issued in pursuance of instruments made or granted pursuant to this Resolution) shall not exceed 20.0 per cent. Of the issued share capital of the Company excluding treasury shares (as calculated in accordance with sub-paragraph (b) below);

(b) (subject to such manner of calculation as may be prescribed by the SGX-ST) for the purpose of determining the aggregate number of Shares that may be issued under paragraph (a) above, the percentage of issued share capital shall be based on the issued share capital of the Company excluding treasury shares at the time this Resolution is passed, after adjusting for:

(i) new Shares arising from the conversion or exercise of any convertible securities or share options or vesting of share awards which are outstanding or subsisting at the time this Resolution is passed; and

(ii) any subsequent bonus issue, consolidation or subdivision of Shares;

(c) in exercising the authority conferred by this Resolution, the Company shall comply with the provisions of the Listing Manual of the SGX-ST for the time being in force (unless such compliance has been waived by the SGX-ST) and the Articles of Association for the time being of the Company; and

(d) (unless revoked or varied by the Company in general meeting) the authority conferred by this Resolution shall continue in force until the conclusion of the next annual general meeting of the Company or the date by which the next annual general meeting of the Company is required by law to be held, whichever is earlier.

[See explanatory Note 3]

7 Renewal of General Mandate for Interested Person Transactions — Resolution 7

That for the purposes of Chapter 9 of the Listing Manual ("**Chapter 9**") of the SGX-ST:

(a) approval be and is hereby given for the renewal of the general mandate permitting the Company and its subsidiaries that are "entities at risk" (as that term is used in Chapter 9), or any of them, to enter into any of the transactions falling within the types of interested person transactions, particulars of which are set out in the Appendix to this Notice of Annual General Meeting (the "**Appendix**"), with any party who is of the class of interested persons described in the Appendix, provided that such transactions are made on normal commercial terms and in accordance with the review procedures for such interested person transactions (the "**IPT Mandate**");

(b) the IPT Mandate shall, unless revoked or varied by the Company in general meeting, continue in force until the conclusion of the next annual general meeting of the Company; and

(c) the Directors of the Company and/or any of them be and are hereby authorised to complete and do all such acts and things (including executing all such documents as may be required) as they and/or he may consider expedient or necessary or in the interests of the Company to give effect to the IPT Mandate and/or this Resolution.

[See Explanatory Note 4]

8 To transact any other business as may properly be transacted at an annual general meeting.

By order of the board

Sally Ting / Jennifer Lee
Joint Company Secretaries

9 April 2019, Singapore

Notice of Annual General Meeting

Notes :

1. Poll.

All the resolutions proposed at the Annual General Meeting will be voted on by way of poll.

2. Depositors.

Under the Articles of Association of the Company (the "Articles"), unless The Central Depository (Pte) Limited ("CDP") specifies otherwise in a written notice to the Company, CDP is deemed to have appointed as CDP's proxies to vote on behalf of CDP at the Annual General Meeting each of the persons (who are individuals) holding shares in the capital of the Company through CDP and whose shares are entered in the Depository Register (as defined in Section 81SF of the Securities and Futures Act, Chapter 289 of Singapore) ("Depositors"), whose names are shown in the records of CDP as at a time not earlier than 72 hours prior to the time of the Annual General Meeting supplied by CDP to the Company, and such appointment of proxies shall not require an instrument of proxy or the lodgement of any instrument of proxy.

A Depositor who is not a relevant intermediary may appoint not more than two persons (who shall be natural persons) to attend and vote in his place as proxy or proxies of CDP in respect of his shareholding, and a Depositor who is a relevant intermediary may appoint more than two persons (who shall be natural persons) to attend and vote in its place as proxy or proxies of CDP in respect of its shareholding, by completing and submitting the Depositor Proxy Form. "Relevant intermediary" has the meaning ascibed to it in section 181 of the Singapore Companies Act, Chapter 50.

The submission of a Depositor Proxy Form shall not preclude a Depositor appointed as a proxy by virtue of the Articles from attending and voting at the Annual General Meeting but in the event of attendance by such Depositor, the Depositor Proxy Form submitted bearing his name as the Nominating Depositor (as defined in the Articles) shall be deemed to be revoked. The Company will reject a Depositor Proxy Form if the Nominating Depositor's name is not shown in the records of CDP as at a time not earlier than 72 hours prior to the time of the Annual General Meeting supplied by CDP to the Company.

Where a Depositor is a corporation and wishes to be represented at the Annual General Meeting, it must appoint a person or persons (who shall be natural persons) to attend and vote as proxy or proxies of CDP at the Annual General Meeting in respect of its shareholding, by completing and submitting the Depositor Proxy Form.

3. Members.

A member of the Company (other than CDP) who is not a relevant intermediary and who is the holder of two or more shares is entitled to appoint not more than two proxies to attend and vote instead of him, and a member of the Company (other than CDP) who is a relevant intermediary and who is the holder of two or more shares is entitled to appoint more than two proxies to attend and vote instead of him, by completing and submitting the Shareholder Proxy Form. "Relevant intermediary" has the meaning ascribed to it in Section 181 of the Singapore Companies Act, Chapter 50.

A proxy need not be a shareholder of the Company. Delivery of the Shareholder Proxy Form shall not preclude a shareholder from attending and voting in person at the Annual General Meeting and in such event, the Shareholder Proxy Form shall be deemed to be revoked.

4. Deposit of Instrument of Proxy.

The instrument appointing a proxy or proxies (together with the power of attorney, if any, under which it is signed or a certified copy thereof) must be deposited at the office of M & C Services Private Limited at 112 Robinson Road #05-01 Singapore 068902 at least 72 hours before the time appointed for holding the Annual General Meeting.

5.Personal Data Privacy.

By submitting an instrument appointing a proxy(ies) and/or representative(s) to attend, speak and vote at the Annual General Meeting and/or any adjournment thereof, a shareholder of the Company or, as the case may be, a Depositor (i) consents to the collection, use and disclosure of the shareholder's or, as the case may be, the Depositor's personal data by the Company (or its agents or service providers) for the purpose of the processing, administration and analysis by the Company (or its agents or service providers) of proxies and representatives appointed for the Annual General Meeting (including any adjournment thereof) and the preparation and compilation of the attendance lists, minutes and other documents relating to the Annual General Meeting (including any adjournment thereof), and in order for the Company (or its agents or service providers) to comply with any applicable laws, listing rules, regulations and/or guidelines (collectively, the "Purposes"), (ii) warrants that where the shareholder or, as the case may be, the Depositor discloses the personal data of the shareholder's or, as the case may be, the Depositor's proxy(ies) and/or representative(s) to the Company (or its agents or service providers), the shareholder or, as the case may be, the Depositor has obtained the prior consent of such proxy(ies) and/or representative(s) for the collection, use and disclosure by the Company (or its agents or service providers) of the personal data of such proxy(ies) and/or representative(s) for the Purposes, and (iii) agrees that the shareholder or, as the case may be, the Depositor will indemnify the Company in respect of any penalties, liabilities, claims, demands, losses and damages as a result of the shareholder's or, as the case may be, the Depositor's breach of warranty.

Explanatory Notes :

Resolutions 2 to 3

1. Detailed information on these Directors can be found in the sections entitled "Board of Directors" and "Additional Information on Directors Seeking Re-appointment" of the Company's 2018 Annual Report.
   (a) Mr. Tan Ek Kia, upon re-election as a Director of the Company, will remain as Chairman of each of the Executive Committee and Nominating Committee, and a member of the Audit and Risk Management Committee. Mr. Tan Ek Kia is considered to be independent by the Board for the purposes of Rule 704(8) of the Listing Manual of the SGX-ST.
   (b) Mr. Duane Carl Radtke, upon re-election as a Director of the Company, will remain as Chairman of the Remuneration Committee and a member of the Nominating Committee.

Resolution 4

2. SGD to USD exchange rates of 1.37:1 and 1.35:1 were used for the financial years ended 31 December 2018 and 31 December 2017, respectively.

Resolution 6

3. Resolution 6 is to empower the Directors to issue shares in the capital of the Company and/or to make or grant Instruments (as defined in Resolution 6). The aggregate number of Shares which may be issued pursuant to Resolution 6 (including new Shares to be issued in pursuance of Instruments made or granted pursuant to Resolution 6) shall not exceed 50.0 per cent. of the issued share capital of the Company excluding treasury shares, with a sub-limit of 20.0 per cent. for Shares issued other than on a pro rata basis to Shareholders. For the purpose of determining the aggregate number of Shares that may be issued, the percentage of issued Shares shall be based on the total number of issued Shares in the capital of the Company excluding treasury shares at the time of the passing of Resolution 6, after adjusting for (i) new Shares arising from the conversion or exercise of any convertible securities or share options or vesting of share awards which are outstanding or subsisting at the time Resolution 6 is passed; and (ii) any subsequent bonus issue, consolidation or subdivision of Shares.

Resolution 7

4. Resolution 7, if passed, will renew the mandate to allow the Company and its subsidiaries that are "entities at risk" (as that term is used in Chapter 9), or any of them, to enter into certain types of interested person transactions with certain classes of interested persons as described in the Appendix. The authority will, unless revoked or varied by the Company in general meeting, continue in force until the conclusion of the next annual general meeting of the Company. Please refer to the Appendix for further details.

Additional Information on Directors Seeking Re-Appointment

The following additional information on Mr. Tan Ek Kia and Mr. Duane Carl Radtke, both of whom are seeking re-appointment as Directors at the forthcoming Sixth Annual General Meeting, is to be read in conjunction with their respective biographies in the section entitled “Board of Directors” of this Annual Report.

Name of Director	Mr. Tan Ek Kia	Mr. Duane Carl Radtke
Date of last re-appointment (if applicable)	28 April 2016	28 April 2016
Country of principal residence	Singapore	United States of America
The Board's comments on this appointment (including rationale, selection criteria, and the search and nomination process)	The re-election of Mr. Tan as the Independent Non-executive Chairman was recommended by the Nominating Committee and the Board has accepted the recommendation, taking into consideration Mr. Tan's qualifications, expertise, past experiences and overall contribution since his initial appointment.	The re-election of Mr. Radtke as an Independent Non-executive Director was recommended by the Nominating Committee and the Board has accepted the recommendation, taking into consideration Mr. Radtke's qualifications, expertise, past experiences and overall contribution since his initial appointment.
Whether appointment is executive, and if so, the area of responsibility	No	No
Job Title (e.g. Lead ID, AC Chairman, AC Member etc.)	Independent Non-executive Chairman Executive Committee (Chairman) Nominating Committee (Chairman) Audit and Risk Management Committee (Member)	Independent Non-executive Director Remuneration Committee (Chairman) Nominating Committee (Member)
Working experience and occupation(s) during the past 10 years	**2009 – 2014:** Dialog Systems (Asia) Pte Ltd (Director) City Gas Pte Ltd (Chairman & Director) (till 2015) Keppel Offshore & Marine Ltd (Director) CitySpring Infrastructure Management Pte Ltd (Director) (from 2010 till 2012) SMRT Corporation Ltd (Interim CEO) (from 2012 till 2012) SMRT Corporation Ltd (Director) Keppel Corporation Limited (Director) (from 2010) PT Chandra Asli Petrochemical Tbk (VP Commissioner) (from 2011) Transocean Ltd (from 2011) Star Energy Group Holdings Pte Ltd (Chairman & Director) (from 2012) KrisEnergy Ltd (Chairman & Director) (from 2013) Singapore LNG Corporation Pte Ltd (Director) (from 2013) **2014 – 2019:** Please refer to Mr. Tan's biography in the section entitled “Board of Directors”	**2009 – 2014:** Devon Energy Corporation (Director) Smith Industries (Director) (till 2010) Sabine Oil & Gas Corporation KrisEnergy Ltd (Director) Valiant Exploration LLC (President and CEO) **2014 – 2019:** Please refer to Mr. Radtke's biography in the section entitled “Board of Directors”
Shareholding interest in the listed issuer and its subsidiaries	Direct interest: 142,000 Deemed interest: Nil	Direct interest: Nil Deemed interest: 2,000,000
Any relationship (including immediate family relationships) with any existing director, existing executive officer, the issuer and/or substantial shareholder of the listed issuer or of any of its principal subsidiaries	No	No
Conflict of interest (including any competing business)	Mr. Tan is an independent non-executive Director of Keppel Offshore & Marine Ltd. and Keppel Corporation Limited (a controlling shareholder of the Company), however he is not accustomed or under an obligation, whether formal or informal, to act in accordance with the directions, instructions or wishes of Keppel Offshore Marine Ltd. or Keppel Corporation Limited.	No
Undertaking (in the format set out in Appendix 7.7) under Rule 720(1) has been submitted to the listed issuer	Yes	Yes

Name of Director		Mr. Tan Ek Kia	Mr. Duane Carl Radtke
Disclose the following matters concerning an appointment of director, chief executive officer, chief financial officer, chief operating officer, general manager or other officer of equivalent rank. If the answer to any question is "yes", full details must be given.			
(a)	Whether at any time during the last 10 years, an application or a petition under any bankruptcy law of any jurisdiction was filed against him or against a partnership of which he was a partner at the time when he was a partner or at any time within 2 years from the date he ceased to be a partner?	No	No
(b)	Whether at any time during the last 10 years, an application or a petition under any law of any jurisdiction was filed against an entity (not being a partnership) of which he was a director or an equivalent person or a key executive, at the time when he was a director or an equivalent person or a key executive of that entity or at any time within 2 years from the date he ceased to be a director or an equivalent person or a key executive of that entity, for the winding up or dissolution of that entity or, where that entity is the trustee of a business trust, that business trust, on the ground of insolvency?	No	No
(c)	Whether there is any unsatisfied judgment against him?	No	No
(d)	Whether he has ever been convicted of any offence, in Singapore or elsewhere, involving fraud or dishonesty which is punishable with imprisonment, or has been the subject of any criminal proceedings (including any pending criminal proceedings of which he is aware) for such purpose?	No	No
(e)	Whether he has ever been convicted of any offence, in Singapore or elsewhere, involving a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere, or has been the subject of any criminal proceedings (including any pending criminal proceedings of which he is aware) for such breach?	No	No
(f)	Whether at any time during the last 10 years, judgment has been entered against him in any civil proceedings in Singapore or elsewhere involving a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere, or a finding of fraud, misrepresentation or dishonesty on his part, or he has been the subject of any civil proceedings (including any pending civil proceedings of which he is aware) involving an allegation of fraud, misrepresentation or dishonesty on his part?	No	No
(g)	Whether he has ever been convicted in Singapore or elsewhere of any offence in connection with the formation or management of any entity or business trust?	No	No
(h)	Whether he has ever been disqualified from acting as a director or an equivalent person of any entity (including the trustee of a business trust), or from taking part directly or indirectly in the management of any entity or business trust?	No	No
(i)	Whether he has ever been the subject of any order, judgment or ruling of any court, tribunal or governmental body, permanently or temporarily enjoining him from engaging in any type of business practice or activity?	No	No
(j)	Whether he has ever, to his knowledge, been concerned with the management or conduct, in Singapore or elsewhere, of the affairs of :—	No	No
	(i) any corporation which has been investigated for a breach of any law or regulatory requirement governing corporations in Singapore or elsewhere; or	No	No
	(ii) any entity (not being a corporation) which has been investigated for a breach of any law or regulatory requirement governing such entities in Singapore or elsewhere; or	No	No
	(iii) any business trust which has been investigated for a breach of any law or regulatory requirement governing business trusts in Singapore or elsewhere; or	No	No
	(iv) any entity or business trust which has been investigated for a breach of any law or regulatory requirement that relates to the securities or futures industry in Singapore or elsewhere,	No	No
	in connection with any matter occurring or arising during that period when he was so concerned with the entity or business trust?	No	No
(k)	Whether he has been the subject of any current or past investigation or disciplinary proceedings, or has been reprimanded or issued any warning, by the Monetary Authority of Singapore or any other regulatory authority, exchange, professional body or government agency, whether in Singapore or elsewhere?	No	No

Corporate Information

As at 1 April 2019

Board of Directors

Tan Ek Kia
Independent Non-executive Chairman

Chris Ong Leng Yeow
Non-executive Director

Alan Nisbet
Non-executive Independent Director

Kelvin Tang
Chief Executive Officer, Executive Director and President, Cambodia

John Koh
Non-executive Independent Director

Keith Pringle
Non-executive Independent Director

Kiran Raj
Chief Financial Officer, Alternate Executive Director to Kelvin Tang and Vice President Finance and Administation

Duane Radtke
Non-executive Independent Director

Audit and Risk Management Committee

John Koh | Chairman
Tan Ek Kia
Alan Nisbet
Keith Pringle

Nominating Committee

Tan Ek Kia | Chairman
John Koh
Duane Radtke
Chris Ong Leng Yeow

Remuneration Committee

Duane Radtke | Chairman
Alan Nisbet
Keith Pringle
Chris Ong Leng Yeow

Executive Committee

Tan Ek Kia | Chairman
John Koh
Kelvin Tang

Joint Company Secretaries

Sally Ting
Jennifer Lee

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Singapore Office

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Share Transfer Agent

M&C Services Private Limited
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Auditors

Deloitte & Touche LLP
Public Accountants and Chartered Accountants
6 Shenton Way, OUE Downtown 2, #33-00 Singapore 068809

Audit Partner

Yang Chi Chih
Year Appointed: 2017
Public Accountants and Chartered Accountants
6 Shenton Way, OUE Downtown 2, #33-00 Singapore 068809

Glossary

THIS GLOSSARY CONTAINS EXPLANATIONS AND DEFINITIONS OF CERTAIN TERMS USED IN CONNECTION WITH OUR BUSINESS. THE TERMS AND THEIR ASSIGNED MEANING MAY NOT CORRESPOND TO STANDARD INDUSTRY OR COMMON MEANING OR USAGE OF THESE TERMS.

1C	Low estimate scenario of contingent resources.
1P	Equivalent to proved reserves; denotes low estimate scenario of reserves.
2022 Notes	S$130 million fixed-rate notes due June 2022.
2023 Notes	S$200 million fixed-rate notes due August 2023.
2024 ZCNs	Senior secured zero coupon notes due 2024.
2C	Best estimate scenario of contingent resources.
2P	Equivalent to proved plus probable reserves; denotes best estimate scenario of reserves.
3C	High estimate scenario of contingent resources.
3D seismic data	Geophysical data that depicts the subsurface strata in three dimensions (3D). 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic.
3P	Equivalent to proved plus probable plus possible reserves; denotes high estimate scenario of reserves.
basin	Areas where sedimentary rocks have accumulated over time, which are regarded as good prospects for oil and gas exploration.
bbl	Barrel.
boe	Barrel of oil equivalent.
boepd	Barrel(s) of oil equivalent per day.
bopd	Barrel(s) of oil per day.
Bridge Upsize	US$20 million additional commitment provided by DBS under the RCF.
contingent resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but are not currently considered to be commercially recoverable due to one or more contingencies.
DBS	DBS Bank Ltd.
DD&A	Depreciation, depletion and amortisation.
DMO	Domestic Market Obligation.
EBITDAX	Earnings before interest, tax, depreciation, amortisation, geological and geophysical expenses and exploration expenses. EBITDAX is used when reporting earnings for oil and mineral exploration companies. Excluding geological and geophysical expenses and provides the true EBITDA of the firm.
EHSS	Environmental, Health, Safety and Security.
EPT	Excess profit tax.
Executive Director	A Director of our Group who performs an executive function.
FEED	Front-end engineering and design.
FOB	Free-on-board.
FSO	Floating, storage and offloading vessel.
FTP	First Tranche Petroleum.
GDSPNTR	General Department of State Property and Non Tax Revenue.
gross reserves	The total volume of oil and/or gas anticipated to be commercially produced in the future.
IFRS	International Financial Reporting Standards.

ISO 14001	An international environmental management system standard certified by SGS International Certifications and accredited by the Swiss Accreditation service or UK Accreditation Service.
ISO 45001 / OHSAS 18001	An international occupational health and safety management system standard overseen by SGS International Certifications Services and accredited by the Swiss Accreditation Service or Joint Accreditation system of Australia and New Zealand.
KEGOT	KrisEnergy (Gulf of Thailand) Limited.
Keppel Shipyard	Keppel Shipyard Limited.
km	Kilometre.
lifting costs	Costs to operate and maintain oil and gas wells and related equipment, and facilities to bring oil and gas to the surface.
LTI	Loss time injury.
mcf	Thousand cubic feet.
MD	Measured depth, describes the length of the borehole of a well.
mm	Million.
mmboe	Million barrels of oil equivalent.
mmcfd	Million cubic feet per day.
MME	Ministry of Mines and Energy (Cambodia).
MOPU	Mobile offshore production unit.
MP G6	MP G6 (Thailand) Limited.
NEBOSH	National Examination Board in Occupational Safety and Heath.
Northern Gulf	Northern Gulf Petroleum Pte Ltd.
Notes	2022 Notes, 2023 Notes and the 2024 ZCNs.
Notes Exchange Gain	Pursuant to the financial restructuring in 2017, the Group recognised a one-off, non-cash fair value gain on exchange of the 2022 Notes and 2023 Notes as the Notes were recognised at a discount to par value upon exchange.
NSAI	Netherland, Sewell & Associates, Inc.
possible reserves	Those additional reserves which analysis of geoscience and engineering data suggests are less likely to be recoverable than probable reserves.
probable reserves	Those additional reserves which are less likely to be recoverable than proved reserves but more certain to be recovered than possible reserves.
proved reserves	Those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations.
PSC	Production sharing contract, which is an agreement with the relevant host government, which outlines the fiscal terms for exploring, developing and producing oil and gas within a specified contract area.
QPR	Qualified person's report.
RCF	Revolving Credit Facility.
reserves	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
resources	All quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced.
SGX-ST	Singapore Exchange Securities Trading Limited.
sq. km	Square kilometre.
TVDSS	Total vertical depth subsea.
TVT	True vertical thickness.
Warrants	Detachable warrants issued pursuant to the preferential offering of the 2024 ZCNs, each warrant carrying the right to subscribe for one new share.
work program	An annual budget program that defines the seismic, well drilling and facilities construction plans.
working interest	Percentage ownership in a joint operation associated with revenue and costs. Working interests do not take intoaccount the terms of any royalties, government shares of production, or similar fiscal terms, and thus do not reflect net entitlement to any oil or gas produced.

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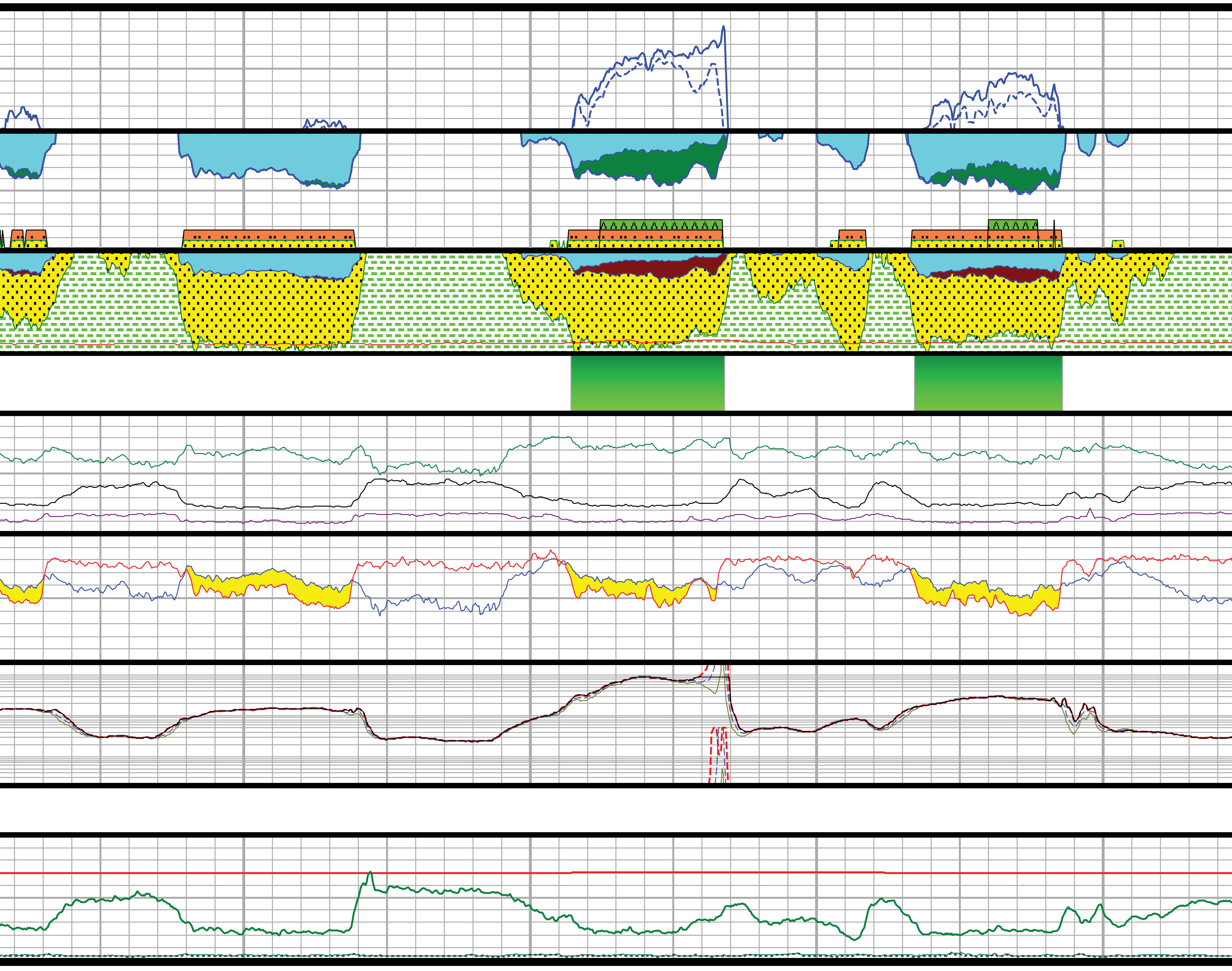

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