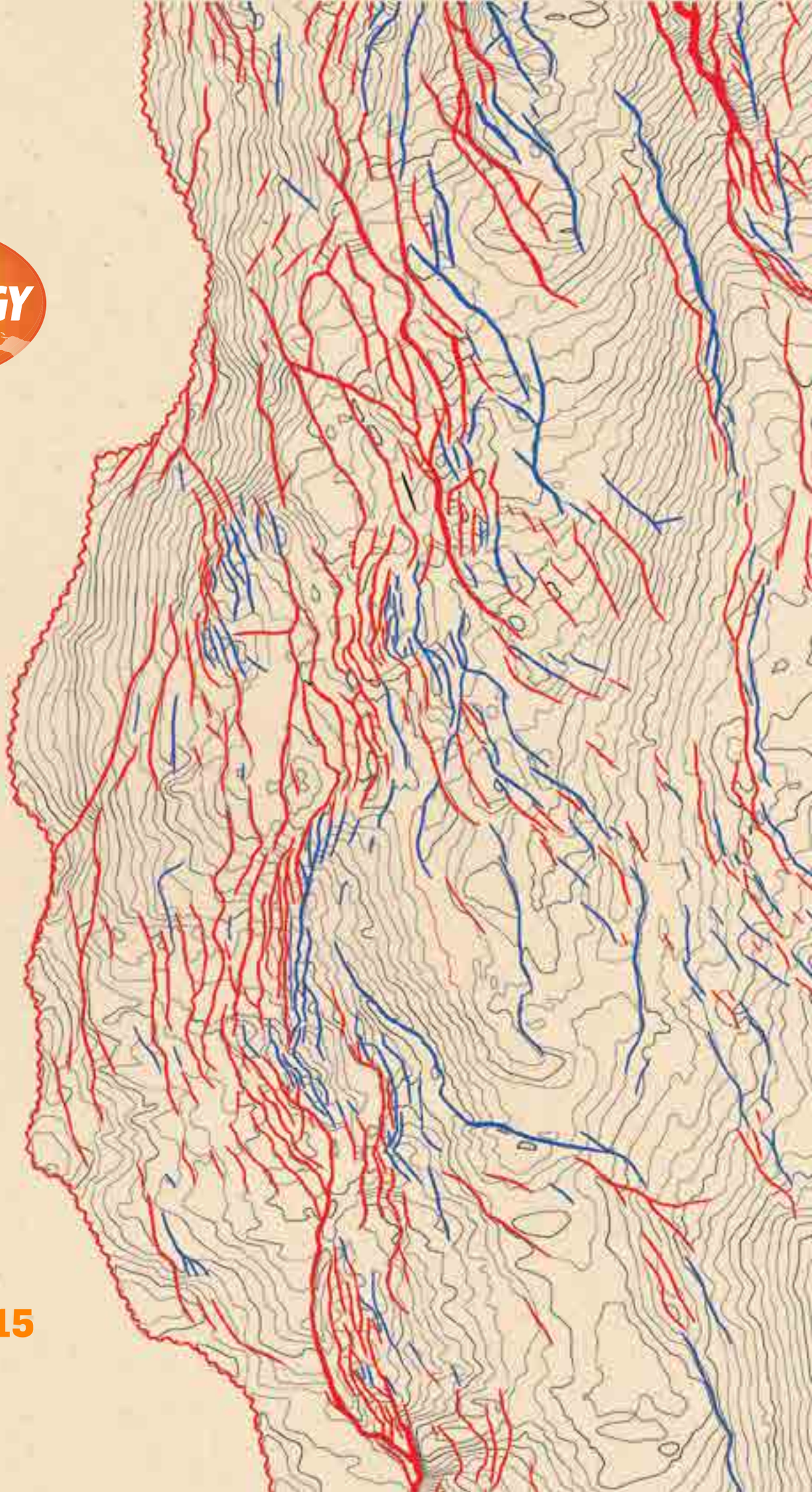
KRISENERGY



Annual Report 2015

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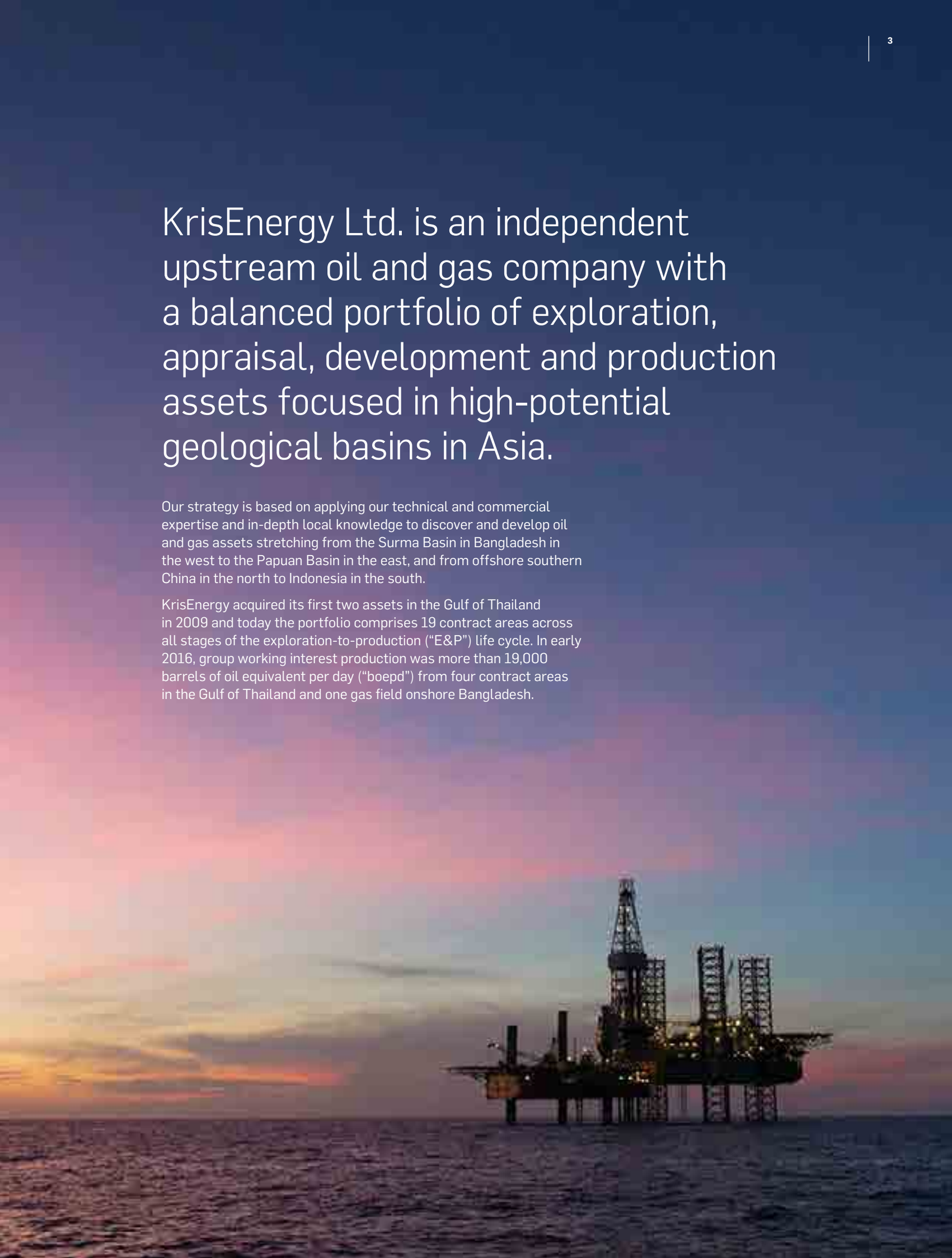
KrisEnergy Ltd. is an independent upstream oil and gas company with a balanced portfolio of exploration, appraisal, development and production assets focused in high-potential geological basins in Asia.

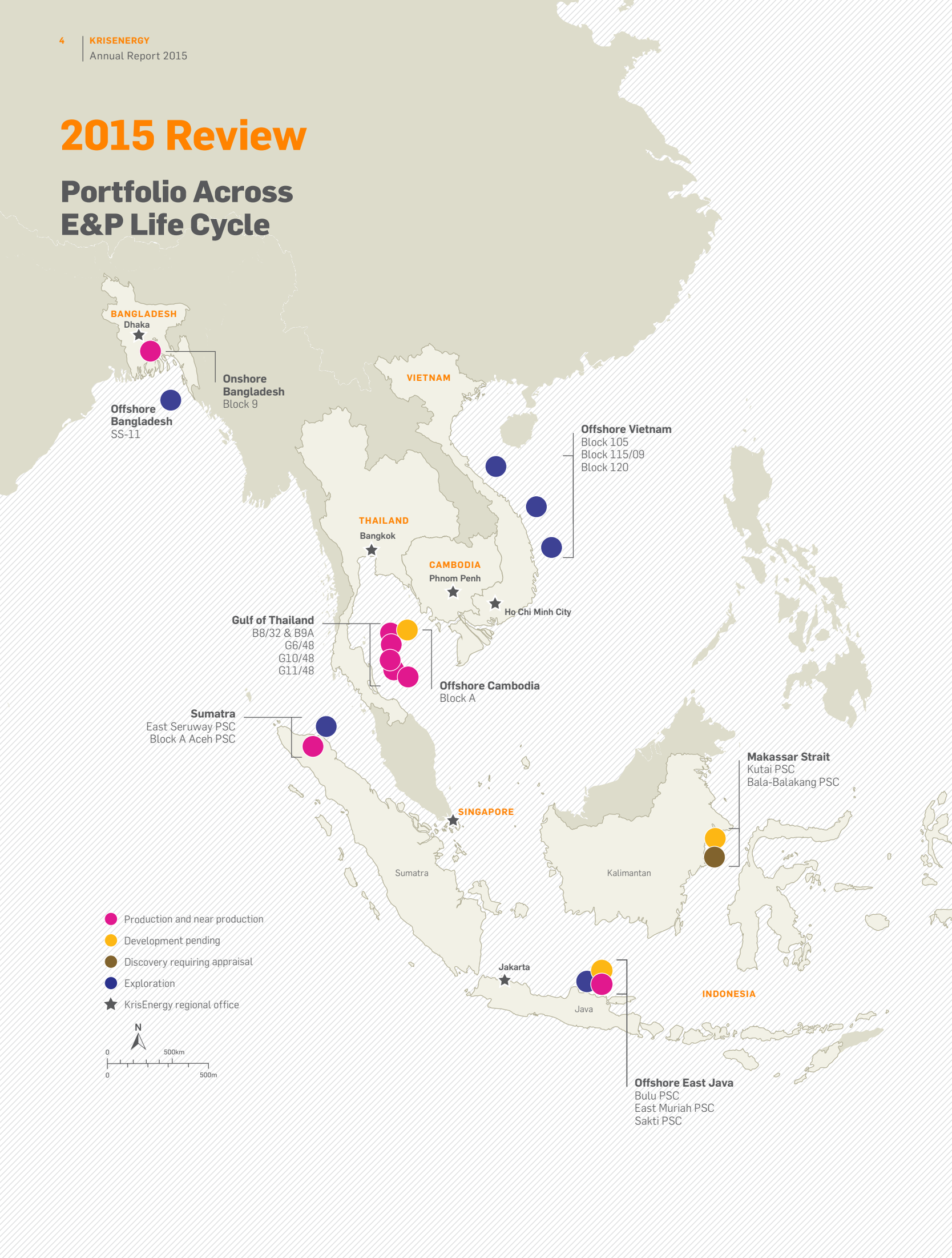
Our strategy is based on applying our technical and commercial expertise and in-depth local knowledge to discover and develop oil and gas assets stretching from the Surma Basin in Bangladesh in the west to the Papuan Basin in the east, and from offshore southern China in the north to Indonesia in the south.

KrisEnergy acquired its first two assets in the Gulf of Thailand in 2009 and today the portfolio comprises 19 contract areas across all stages of the exploration-to-production ("E&P") life cycle. In early 2016, group working interest production was more than 19,000 barrels of oil equivalent per day ("boepd") from four contract areas in the Gulf of Thailand and one gas field onshore Bangladesh.



2015 Review

Portfolio Across E&P Life Cycle



COUNTRY / ASSET NAME	WORKING INTEREST (%)	OPERATOR	GROSS ACREAGE (SQ. KM)	LOCATION	WATER DEPTHS (METRES)
BANGLADESH					
Block 9	30	KrisEnergy	1,770	Surma Basin	Onshore
SS-11	45	Santos	4,475	Bay of Bengal over Bengal Fan	200-1,500
GULF OF THAILAND					
B8/32 & B9A	4.6345	Chevron	2,072	North Pattani Basin	42-113
G10/48	100[1]	KrisEnergy	4,696	Southern margin of Pattani Basin	Up to 60
G11/48	22.5	Mubadala	3,374	Southern Pattani Basin and northwest Malay Basin	Up to 75
G6/48	30	KrisEnergy	566	Karawake Basin on western margin of Pattani Basin	60-70
CAMBODIA					
Block A	52.25[2]	KrisEnergy	4,709	Khmer Basin	50-80
INDONESIA					
East Seruway PSC	100	KrisEnergy	1,172	North Sumatra Basin, Malacca Strait	25-60
Block A Aceh	41.6666	Medco	1,680	North Sumatra Basin	Onshore
Bulu PSC	42.5	KrisEnergy	697	East Java Sea	50-60
East Muriah PSC	50	KrisEnergy	995	East Java Sea	50-65
Sakti PSC	95	KrisEnergy	4,974	East Java Sea	50-60
Kutai PSC	54.6	KrisEnergy	944	Mahakam River delta, Makassar Strait	50-90
Bala-Balakang PSC	85	KrisEnergy	3,143	Southern edge of Kutai Basin, Makassar Strait	20-over 1,000
Udan Emas PSC	100	KrisEnergy	4,044	Bintuni Basin, West Papua	Transition
VIETNAM					
Block 105-110/04[3]	51	KrisEnergy	7,192	Central Song Hong Basin	20-80
Block 115/09	100	KrisEnergy	7,382	Quang Ngai Graben into Phu Khanh Basin	60-200
Block 120	33.33	Eni	6,869	Southern Song Hong Basin	50-650

1 KrisEnergy has an effective 89% working interest in G10/48
2 After a 5% transfer of working interest to the Cambodian Ministry of Mines & Energy("MME")
3 Block 105-110/04 ("Block 105")

Our target area stretches from the Surma Basin in Bangladesh in the west to the Papuan Basin in the east, and from offshore southern China in the north to Indonesia in the south.

Our offices

We are dedicated to establishing and maintaining an on-the-ground presence in countries in which we have assets. We currently have offices in Dhaka in Bangladesh, Phnom Penh in Cambodia, Jakarta in Indonesia, in Singapore, Bangkok in Thailand and in Ho Chi Minh City in Vietnam. In addition, we have a full complement of operational staff at the Bangora field location onshore Bangladesh.

By maintaining local offices in these countries, we are able to respond quickly and efficiently to business opportunities that arise in these areas. Moreover, we largely employ local technical and professional staff, who bring valuable knowledge of the regional geology, business culture and regulatory environment.

2015 Operational Highlights

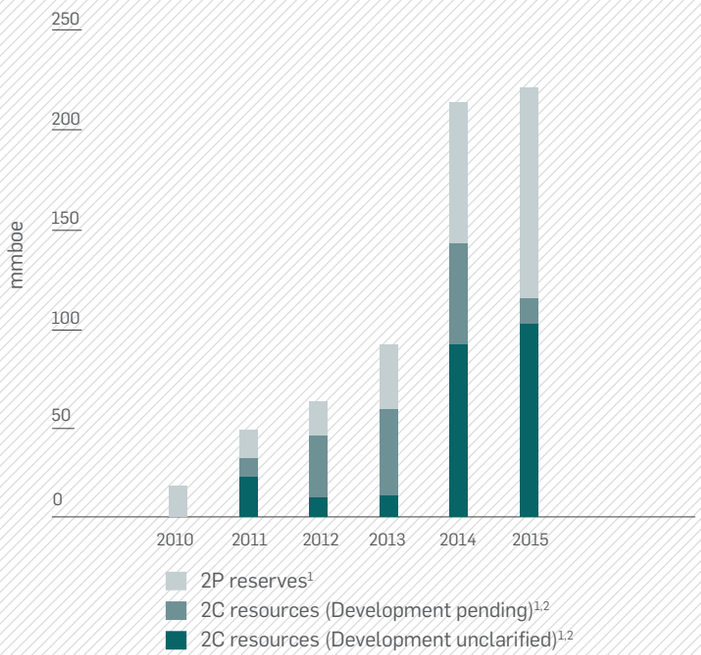
Two oil developments completed & onstream

- KrisEnergy-operated Wassana field in G10/48, Gulf of Thailand, produced first oil on 14 August 2015. Drilling of 14 development wells was completed in January 2016 when gross production briefly reached a peak at approximately 12,800 barrels of oil per day ("bopd"). The field was producing at a plateau of 11,000 bopd in early 2016
- Nong Yao field in G11/48, Gulf of Thailand, commenced production on 17 June 2015. Drilling of 16 development wells was completed in November 2015 when production briefly rose to approximately 11,400 bopd before running at a plateau rate of 10,000 bopd in early 2016

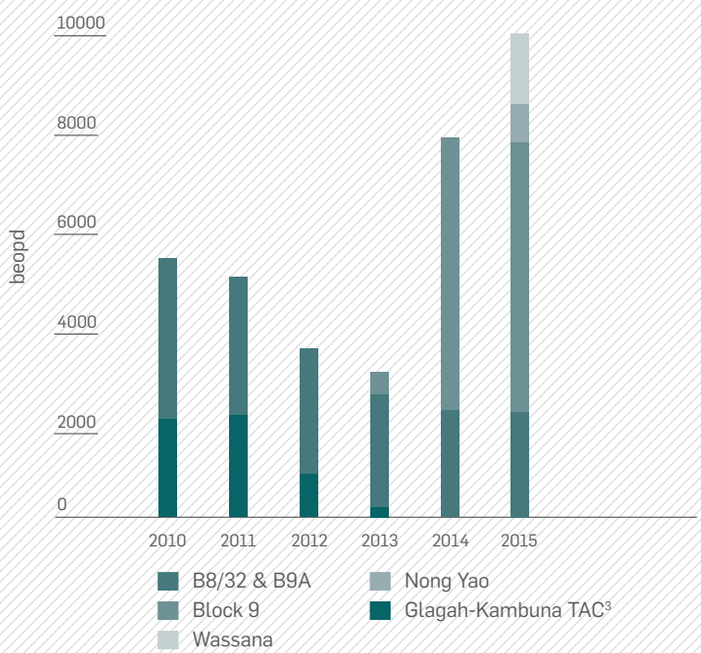
Focus on gas development in Indonesia

- Preliminary construction work began in November 2015 at the Block A Aceh gas development onshore Sumatra. A gas sales agreement was signed in January 2015 with a gas price of US$9.45 per million British thermal units ("mmBtu")
- Front-end engineering and design was completed in October 2015 for the Lengo gas development in the KrisEnergy-operated Bulu production sharing contract ("PSC") offshore East Java. Steps are underway to issue the tender for engineering, procurement, construction and installation

5th consecutive year of 2P reserves growth



Production hits record



Proved plus probable ("2P") reserves[1] increased 49% to 105.9 million barrels of oil equivalent ("mmboe") as at 31 December 2015 as a result of progress on a gas development project in Indonesia and exploration success in the Gulf of Thailand. All 2P reserves and best estimate ("2C") contingent resources[1] are reviewed annually by third-party independent consultant Netherland, Sewell & Associates, Inc. ("NSAI"):

- Working interest 36.8 mmboe in aggregate upgraded to 2P reserves from 2C resources associated with Block A Aceh gas development, Rossukon oil discoveries in G6/48 and potential satellite development in the Greater Wassana Area in G10/48
- 2C resources decreased 27.4 mmboe to 109.3 mmboe due to transfers to 2P reserves

- Average working interest production in 2015 increased 27.3% to 9,692 boepd as the new Nong Yao and Wassana fields ramped up in the second half of the year
- In early 2016, average working interest production reached a plateau at more than 19,000 boepd
- New oil fields result in 68% oil to 32% gas production mix; Company turns focus to Indonesian gas developments

New oil development confirmed

- 100% exploration success rate in the Rossukon discovery area in the KrisEnergy-operated G6/48 contract area resulted in the Thai authorities approving a production area licence in November 2015. Work is underway to finalise the Rossukon development concept

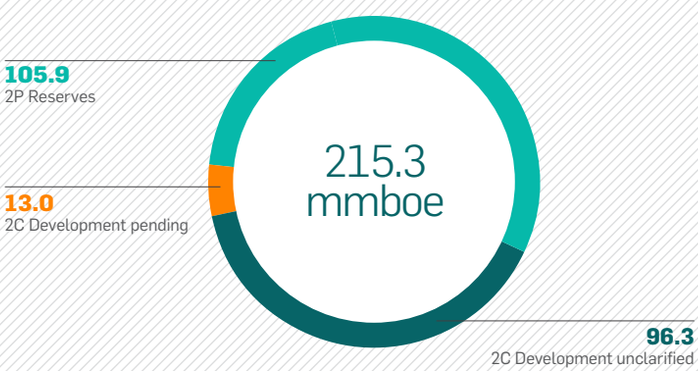
West Papua seismic completed

- A 300 km transition zone 2D seismic acquisition program and a 12,210 sq. km airborne gravity and magnetic survey were completed in June 2015 in the Udan Emas PSC in West Papua. The project took more than two million man-hours and more than 1,400 workers were in-field at the height of activity

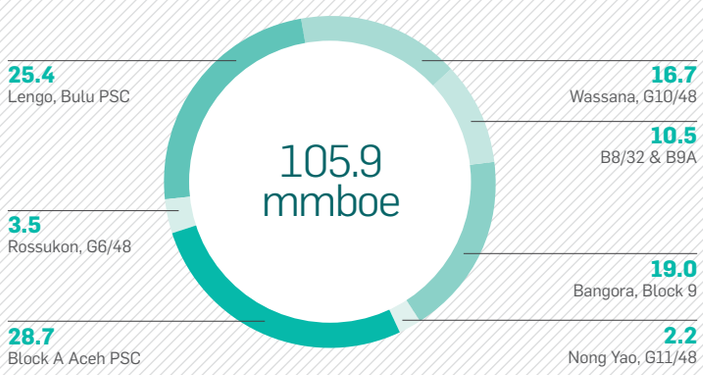
Reserves & resources

All volumes are estimated by NSAI as at 31 December 2015. Numbers may not add up due to rounding.

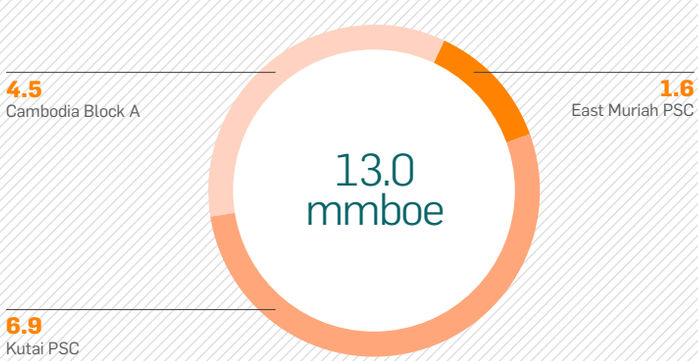
Total 2P reserves & 2C resources (mmboe)



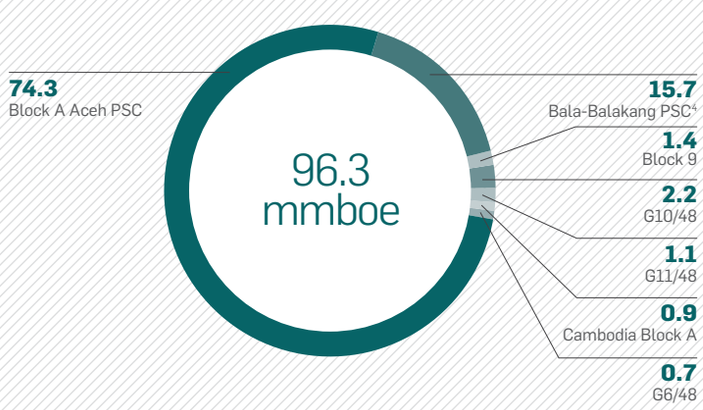
Production/near production 2P reserves (mmboe)



Development pending 2C resources (mmboe)



Development unclarified 2C resources (mmboe)



1 2P reserves refer to proved plus probable reserves and 2C resources refers to best estimate contingent resources in accordance with the definitions and guidelines in the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers
2 Development pending refers to a discovered accumulation where project activities are ongoing to justify commercial development in the forseeable future. 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
3 The Kambuna gas field in the Glagah-Kambuna Technical Assistance Contract ceased production in July 2013
4 In 2015, the Indonesian authorities approved the renaming of the Bala-Balakang PSC, formerly the Tanjung Aru PSC. KrisEnergy's working interest in the Bala-Balakang PSC increased to 85% from 43% in 2015 following the withdrawal of a joint-venture partner

2015 Financial Highlights

Revenue (US$)

60.2 million

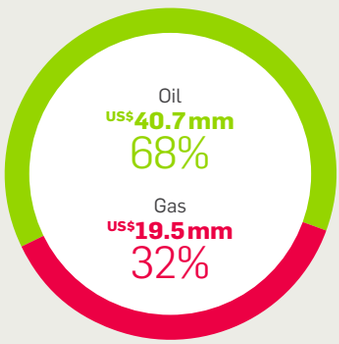
(2014: 74.9 million)

EBITDAX [1] (US$)

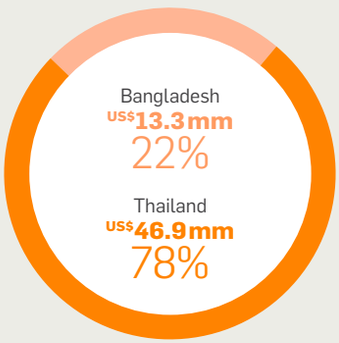
37.2 million

(2014: 30.5 million)

Revenue by oil to gas ratio



Revenue by country breakdown



Gearing

38.1%

(2014: 38.1%)

Lifting Cost (US$)

8.49/boe

(2014: 6.52/boe)

Loans & Borrowings (US$)

304.6 million

(2014: 257.4 million)

Oil & Gas Assets (US$)

862.5 million

(2014: 539.1 million)

Realised Oil Sales Price (US$)

40.18/bbl

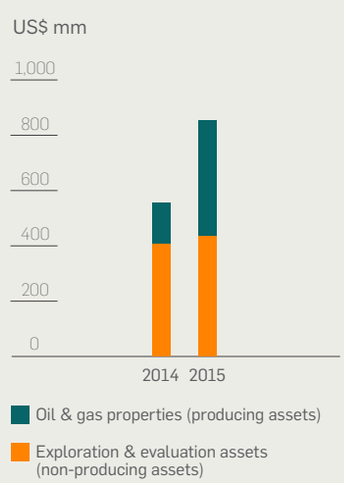
(2014: 100.93/bbl)

Realised Gas Sales Price (US$)

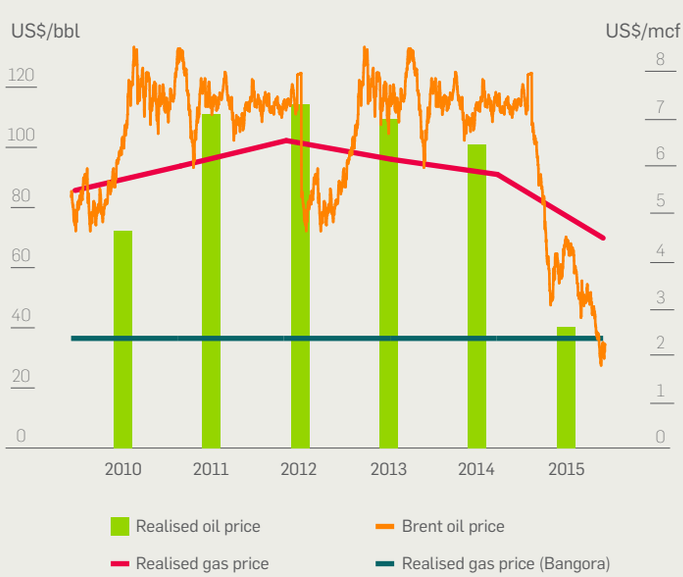
4.45/mcf

(excludes Bangladesh)
(2014: 5.80/mcf)

Breakdown of oil & gas assets



Realised prices versus Brent



The realised price from Bangora field in Bangladesh was US$2.32 / mcf, unchanged from 2014

[1] Earnings before interest, tax, amortisation, geological and geophysical expenses and exploration expenses

General and administrative costs were down by one-third in 2015 and capital expenditure for 2016 has been reduced by a substantial 78%.

Chairman's Statement

Will Honeybourne
Non-Executive Chairman

Dear Shareholders,

Turmoil in financial markets and severe downward pressure on crude oil prices created instability and uncertainty throughout the oil and gas industry during 2015. Investor confidence in the sector has been shaken, the cost of capital has increased substantially and access to financing – both debt and equity – has been severely curbed.

It is unfortunate, though not surprising, that these exceptional circumstances have overshadowed the considerable accomplishments of the KrisEnergy team over the past 12 months.

The Company began 2015 with three producing assets and 7,700 boepd in average working interest production. By year's end, volumes exceeded 19,000 boepd from five producing areas, including our first operated development, Wassana. A string of exploration successes and progress on other development projects resulted in another milestone being crossed as proved plus probable reserves broke the 100 mmboe mark for the first time.

These are truly transformational achievements for any young E&P company and are a testament to the excellent in-house operational and technical capabilities upon which KrisEnergy has been built over the past six years. KrisEnergy's portfolio continues to be strengthened as a platform for future opportunities in Southeast Asia.

Cost reduction

KrisEnergy's management team has been decisive in implementing necessary financial strategies to chart a course through this challenging stage of the commodity cycle with a continuing emphasis on maintaining financial liquidity as decreasing oil prices negatively impacted the Company's revenues. General and administrative costs were down by one-third in 2015 and the budgeted capital expenditure for 2016 has been reduced by a substantial 78%.

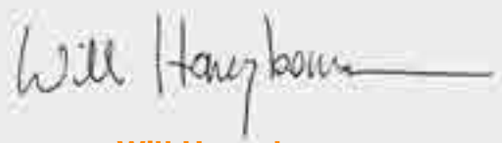
As part of the cost reduction efforts, Non-Executive Directors have volunteered to take a 25% cut in all fees, effective 1 January 2016. The Executive Directors and senior management have taken similar cuts in compensation, bonuses for 2015 have been completely cut, employees are receiving lower remuneration and staffing levels have been reduced.

Governance

The composition of the Board was unchanged in 2015. However, two new Board Committees were established to strengthen transparency and oversight. The Investment Review Committee provides advisory support to management as well as recommendations to the Board for any major transactions. The Technical Committee convenes on an *ad hoc* basis and reviews the Group's exploration and appraisal plans and activities, field development plans, technical evaluations on acreage or asset acquisitions, and issues regarding health, safety and the environment.

On behalf of the Board, I would like to thank the entire KrisEnergy team for their hard work and dedication and for making 2015 an outstanding year in the Company's evolution. I would like to thank management for their leadership during these difficult times and our shareholders for their patience and support in spite of the significant fall in KrisEnergy's share price.

With continued pressure on global oil prices, 2016 is likely to be another challenging year for the upstream industry with more tough decisions to be taken. However, I have every confidence in our team to make those decisions in a timely manner with both the utmost professionalism and the full interests of all stakeholders carefully taken into consideration.



Will Honeybourne
Non-Executive Chairman
29 February 2016

>19,000 boepd
DEC 2015 | 5 PRODUCING ASSETS

7,700 boepd
JAN 2015 | 3 PRODUCING ASSETS

Chief Executive Officer's Review

Keith Cameron

Chief Executive Officer

The upstream industry is enduring one of its most challenging cyclical downturns in decades and a confluence of factors – the crash in oil prices, stymied economic growth and political upheaval – have taken a toll on investor confidence. These grim conditions may last well into 2016 before any eventual recovery in oil prices is sustained.

Nevertheless, we can look back on 2015 as a groundbreaking year for KrisEnergy Ltd., one in which the challenging external environment tested the mettle of our management skills and the ability to adapt our business to rapidly deteriorating market conditions.

Operationally, the Group fulfilled its targets, completing two new oil developments in the Gulf of Thailand while demonstrating technical prowess with a highly successful exploration drilling program, which resulted in an approved production licence for the future Rossukon oil development.

These milestones, together with strong growth in production – approximately 19,000 boepd in early 2016 – and a 49% uplift in 2P reserves to almost 106 mmboe, underpin our mission to become a sustainable and best-in-class exploration and production operator in Asia.

It is unfortunate that our significant achievements have been obscured by the continued rout in the oil market, and although our share price saw periods of resilience against the general downward trend, it has inevitably succumbed as external factors weighed on our financial performance.

Revenue for 2015 fell 19.7%, which was a smaller decline than the 60.2% drop we saw in our average realised oil price for the year. Revenue was cushioned somewhat by improved performance at our existing fields – B8/32, B9A and Bangora – as well as the start-up of the Wassana and Nong Yao fields, both in the Gulf of Thailand. These two new oil fields ramped up production to plateau rates in the second half of 2015 and consequently operating costs, lifting costs and depreciation, depletion and amortisation expenses all rose on a year-on-year basis.

Battening the hatches

We have had to make adjustments as the depth and longevity of the oil price depression became evident.

A S$169.5 million rights issue in August 2015 provided funds to complete development drilling in the Wassana and Nong Yao fields, thereby supporting growth in production, and reducing the Group's net debt to net debt-to-equity ratio to 31.2% at the end of the third quarter. However, the continual decline in oil prices in the fourth quarter led us to incur impairments on our producing assets at year end and a writedown in the value of crude inventory, and resulted in our gearing rising to 38.1%.

We also secured an amendment to one of the financial covenants on our Singapore dollar-denominated debt. Although we were compliant with all our covenants at the time, amending the consolidated EBITDAX to consolidated interest expense ratio provided additional headroom given the oil price slump and doubts over the timing of any recovery.

We are also focused on our expenditure profile in order to manage liquidity. Corporate general and administrative costs were cut by 32.4% in 2015 and we continue to implement further cost controls in 2016, which will unfortunately include a loss in headcount where appropriate and a reduction in remuneration and benefits for all employees. Non-Executive Directors have volunteered a 25% cut in fees.

Capex slashed

Given the sustained low oil price environment, our work program for 2016 will predominantly focus on producing assets to maintain and maximise production efficiencies thereby securing current and future cash flows.

Capital expenditure in 2016 has been set at US$50.8 million, the lowest level since the Company was established in 2009 and down 77.4% from US$224.7 million in 2015 during which we were committed to the Wassana and Nong Yao development projects. We intend to fund capital expenditure from a combination of cash flow from operations, capital market and asset transactions, as well as existing debt facilities and cash resources.

Environment, health & safety ("EHS")

Notwithstanding cost reductions, health and safety remain of paramount importance. Total man-hours spent on KrisEnergy-operated assets in 2015 almost doubled from the previous year to 3,430,879. We unfortunately recorded two lost-time injuries ("LTIs") during development activities at the Wassana oil field in the Gulf of Thailand.

However, the seismic operation in West Papua, which accounted for 90% of the increase in 2015 man-hours, was completed without LTIs, a very satisfying achievement given the number of contracted personnel involved in the project and the extremely difficult terrain and environment.

Outlook

Oil and gas remain primary energy sources globally and demand continues to grow, albeit at a slower pace than in recent years. Economic and demographic drivers are expected to put Asia at the forefront of increasing consumption in the future. In the meantime, the near-term outlook will remain uncertain until oil and equity prices bottom and some confidence is restored to the markets. With our higher levels of oil production at the beginning of 2016, we are well positioned to benefit from any price recovery. Until then, we will continue to steer a cautious path and keep a tight grip on expenditure.

Keith Cameron
Executive Director, Chief Executive Officer
29 February 2016

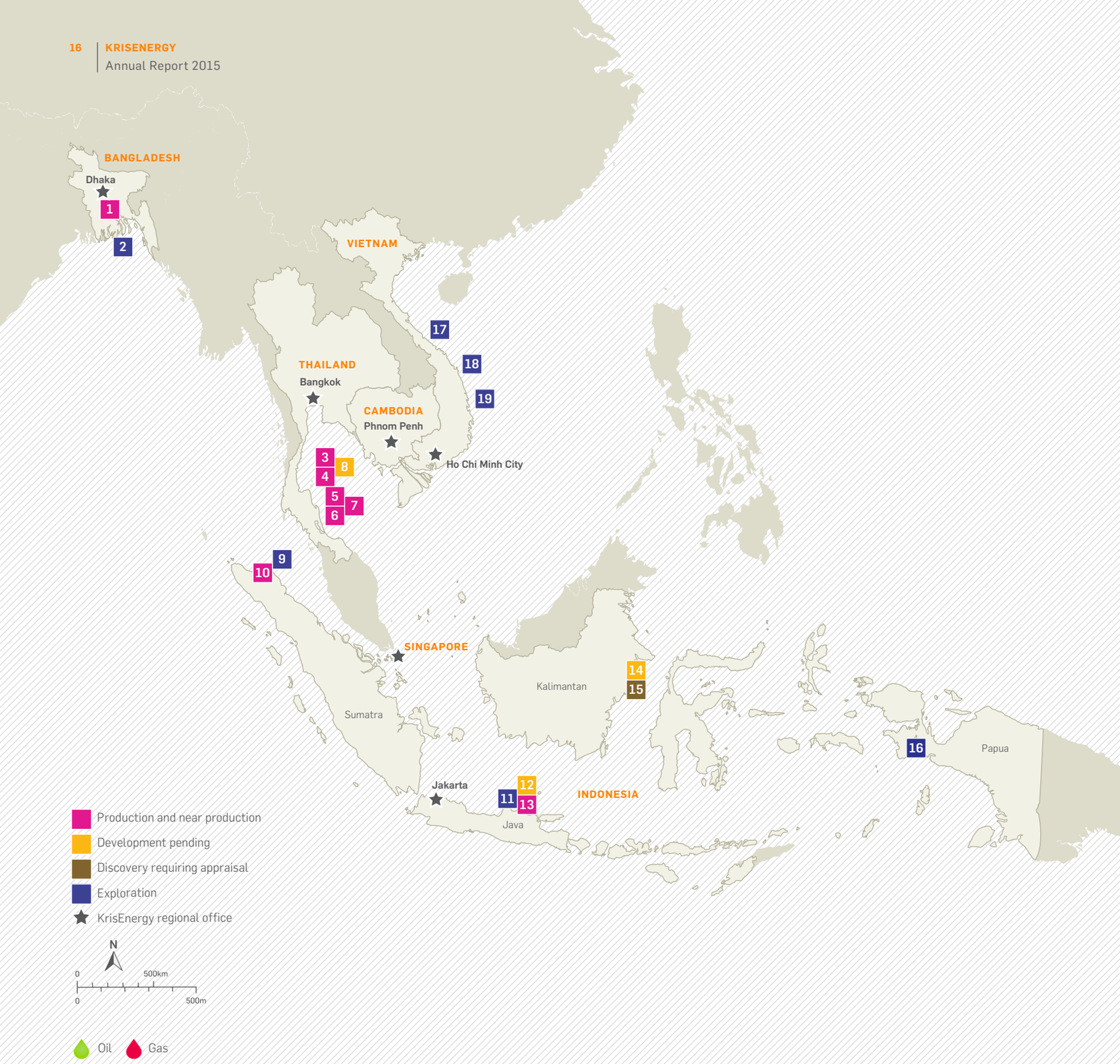
(Top) The *MOPU Ingenium* and the *Key Gibraltar* jack-up rig in the Wassana field in the Gulf of Thailand

(Middle left) Geological and geophysical discussions in Bangkok, Thailand

(Bottom left) Bangora gas field operations in Bangladesh

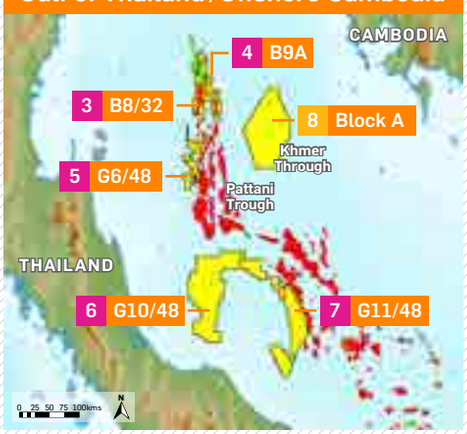
(Bottom right) Shot hole drilling for offshore seismic acquisition in the Udan Emas PSC, West Papua

Portfolio & Technical Review



Onshore / Offshore Bangladesh

Gulf of Thailand / Offshore Cambodia



Onshore / Offshore Sumatra

The Portfolio

As at 29 February 2016, KrisEnergy held working interests in 19 contract areas in five countries.

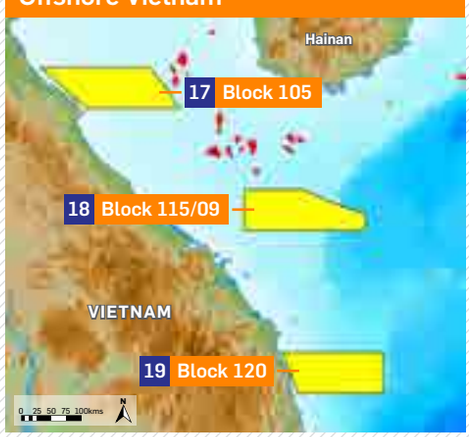
We are mindful of managing risk. Our approach is to build a portfolio of assets across each stage of the E&P life cycle and to spread our exposure to political and fiscal risks by operating in multiple countries with different taxation regimes and regulations.

Our assets are largely in shallow waters in well-explored geological basins. We operate 13 of our 19 assets, giving us control of the work programs and budgets and therefore the flexibility to optimise operations such as drilling and seismic acquisition.

We aim to balance our reserves, resources and production between oil and gas. Commercial oil discoveries are quicker to develop and sell into a ready international spot market at a higher value than the gas equivalent, but the latter is generally sold in Asia under long-term supply contracts and is less vulnerable to the volatility of global benchmark oil prices.

Producing assets provide cash flow with which we explore for hydrocarbons and subsequently appraise and develop our discoveries. We selectively and opportunistically seek new acquisition opportunities with potential value creation upside across the E&P cycle within our available funding and with a full commitment to maintaining rigorous technical, operational and commercial selection standards. Likewise, the divestment of assets is also critical to portfolio management.

Offshore Vietnam



Offshore East Java

Makassar Strait

Onshore West Papua

Technical Review

Chris Gibson-Robinson

Director Exploration & Production

2015 was a year of execution and delivery in which we made great strides operationally in all phases of the E&P life cycle. Two development projects – Wassana and Nong Yao – achieved first oil and resulted in Group production exceeding 19,000 boepd in the first two months of 2016. Advancement on an early-stage gas development in Indonesia led to a hefty uplift in 2P reserves to more than 100 mmboe, marking the fifth consecutive year of reserve growth for the Company. Five successful exploration wells in the Gulf of Thailand and the subsequent approval of the production licence for the Rossukon oil field secured another future development for the project pipeline.

The ramp-up in KrisEnergy-operated activity in 2015 and the accompanying increase in contracted manpower brought focus on our monitoring of health and safety procedures and performance. In total, 3,430,879 man-hours were spent on KrisEnergy-operated assets in 2015, an increase of 93.5% from a year earlier, most of which was attributable to a 2D seismic acquisition program in West Papua where at the height of activity there were more than 1,400 workers in the field. Unfortunately, the Group recorded two LTIs associated with development operations on the Wassana facilities, which accounted for 28.7% of the total man-hours. We have subsequently worked 1,507,642 man-hours since the last LTI.

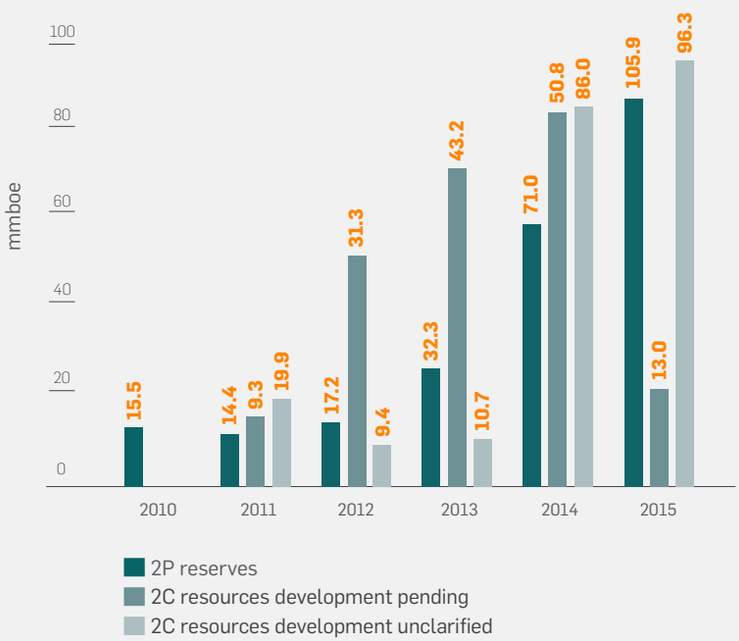
We continue to implement international standards throughout the organisation. Our office in Dhaka and the Bangora field operations in Block 9 received OHSAS 18001 certification in November 2015, adding to the ISO 14001 accreditation achieved in December 2014. Both Jakarta and Singapore are OHSAS 18001 certified and the latter also holds ISO 14001.

2P reserves & 2C resources

Year-end 2015 working interest 2P reserves were estimated by NSAI at 105.9 mmboe, a 49.2% jump from 71.0 mmboe as at 31 December 2014. Progress on the non-operated Block A Aceh gas development, onshore Sumatra, accounted for 82.2% of the reserves increase following NSAI's reclassification of 28.7 mmboe of 2C resources to the 2P category. Other additions to 2P reserves were 3.5 million barrels of oil ("mmbo") attributed to the Rossukon series of oil discoveries in the G6/48 contract area for which a production licence was sanctioned in November 2015, and 4.6 mmbo associated with a potential satellite development in the Greater Wassana Area in G10/48.

For Block 9 in Bangladesh, NSAI raised its estimate for 2P reserves by 1.0 mmboe to almost 19.0 mmboe on a working interest basis after adjustment for production of almost 2.0 mmboe. NSAI reduced the working interest 2P reserves estimate for B8/32 & B9A to 10.5 mmboe as at 31 December 2015 from 11.2 mmboe a year earlier after working interest production of 0.77 mmboe.

NSAI estimated working interest 2C resources at 109.4 mmboe as at 31 December 2015, down 27.4 mmboe from the previous year. The reduction was less than the reclassified resource-to-reserves volumes largely due



2P RESERVES REPLACEMENT

	2010	2011	2012	2013	2014	2015
2P reserves at 31 Dec (mmboe)	15.55	14.38	17.16	32.30	71.00	105.90
Average production (boepd)	4,128	4,817	3,384	2,916	7,612	9,692
Total production (mmboe)	–	1.758	1.235	1.064	2.778	3.573
Reserves replacement ratio (%)	–	17	325	1,523	1,492	1,088

105.9 mmboe

2P RESERVES AT END 2015

+49.2%

VS END 2014

to an increase in the Company's working interest in the Bala-Balakang PSC, formerly the Tanjung Aru PSC, which rose to 85% from 43% following the withdrawal of one of the joint-venture partners. Consequently our working interest 2C resources attributable to Bala-Balakang rose to 15.7 mmboe as at 31 December 2015 from 7.9 mmboe at the end of 2014.

Total 2015 year-end 2P reserves take into account the Group's working interest production of approximately 3.5 mmboe over the 12 months from the Bangora gas field in Block 9 onshore Bangladesh, and B8/32, B9A, G10/48 and G11/48, all in the Gulf of Thailand.

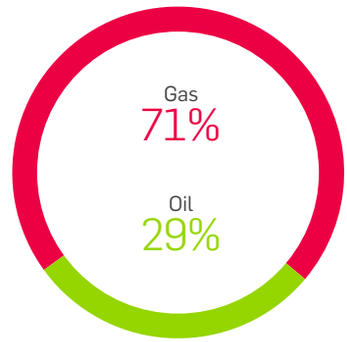
Production—turning on the taps

The completion of the Wassana and Nong Yao development projects saw Group production cross a significant milestone in early 2016, briefly breaching 21,000 boepd for the first time in the Company's six-year history.

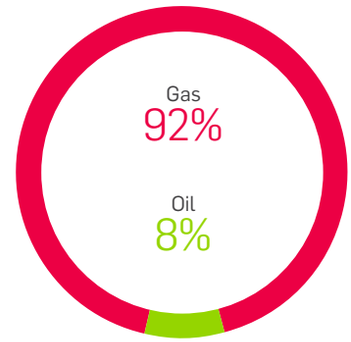
For the full-year 2015, working interest production rose 27.4% to an average 9,692 boepd compared with 7,612 boepd in 2014 with relatively stable performance overall at existing fields – Bangora, B8/32 and B9A – and incremental volumes in the fourth quarter with the ramp-up of Wassana and Nong Yao output. The new crude streams have resulted in a reversal of the Group's oil-to-gas production profile, which was 68% oil to 32% gas at the beginning of 2016 as both Wassana and Nong Yao produced at higher-than-expected rates.

First oil was achieved at the KrisEnergy-operated Wassana oil field on 14 August 2015, 15 months after we took control of operations for the G10/48 contract area and demonstrating our subsurface and technical expertise as well as the strong project management skills within the Company. The development comprises 14 development wells – 13 producers and one water disposal well, the *MOPU Ingenium* mobile offshore production unit and the *Rubicon Vantage* floating, storage and offloading ("FSO") vessel. Upon completion of the Wassana development drilling program in early January 2016, production at the field hit a peak at approximately 12,800 bopd before settling at approximately 11,000 bopd by the end of February. The original forecast for the plateau rate was 10,000 bopd.

The non-operated Nong Yao oil field in G11/48 commenced production on 17 June 2015. The field comprises 16 development wells – 14 producers and two water disposal wells – a wellhead processing platform and a minimum facility wellhead platform with the export of crude via a FSO vessel. Development drilling was completed in November 2015 and the field reached a peak of approximately 11,400 bopd before consistently producing at 10,000 bopd.



2P reserves oil vs gas



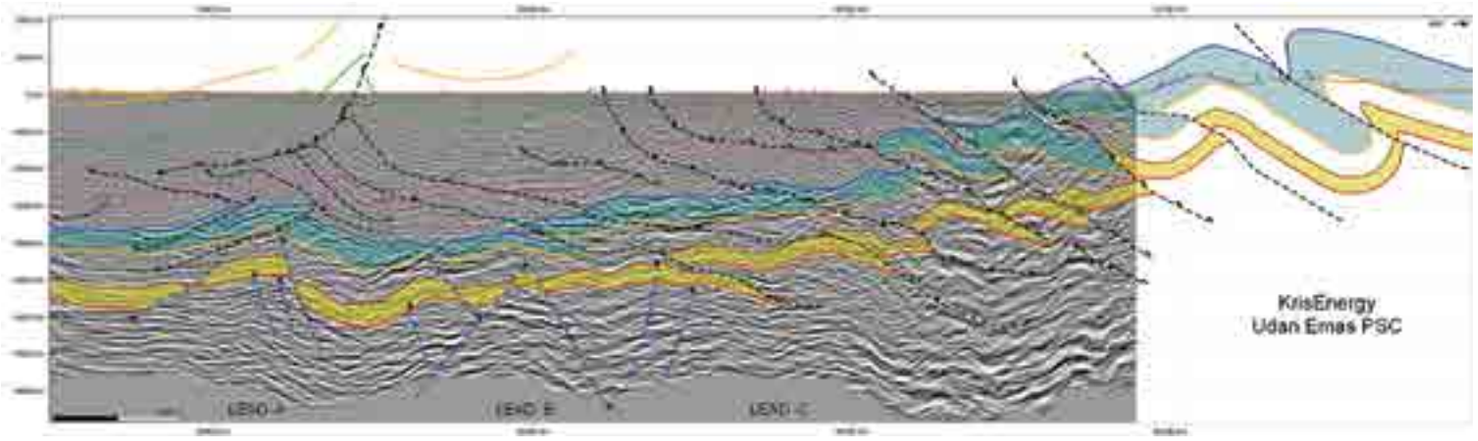
2C resources oil vs gas

An increase in wireline zonal recompletions boosted output at the B8/32 & B9A complex through the fourth quarter 2015 and in the opening months of 2016 when oil production exceeded 30,000 bopd, the highest level since May 2014. Similarly, gas production also increased to more than 148 million cubic feet per day ("mmcfd"), a rate not achieved since June 2012. A total of 52 development wells were drilled in B8/32 & B9A in 2015.

Average production at the Bangora gas field in Block 9 was consistently above 100 mmcfd in 2015, dipping marginally below in October following a 2.5 day-stoppage for maintenance. Two development wells planned to be drilled in 2015 have been deferred until mid-2016.

Development—rebalancing future gas production

Central to our strategy for growth is the timely and efficient development of 2P reserves into production and thereby cash flow. With the successful completion of the Wassana and Nong Yao projects, the next wave of developments will focus on gas in Indonesia, namely onshore Sumatra and offshore East Java, where prices for long-term pipeline gas sales remain attractive.



A seismic and geological cross-section across various leads in the Udan Emas PSC

The non-operated Block A Aceh project comprises the development of three gas fields – Alur Rambong, Alur Siwah and Julu Rayeu – within the PSC area in Aceh province, onshore Sumatra. Sweet gas from Alur Rambong is expected to go into production in 2018 followed by sour gas from Alur Siwah. The plateau production rate will be approximately 70 mmcfd. In January 2015, the operator, P.T. Medco E&P Malaka, signed a gas sales agreement for a daily contracted quantity of 58 billion British thermal units at an agreed gas price of US$9.45 per mmBtu.

Progress has been made on the Lengo gas development in the KrisEnergy-operated Bulu PSC offshore Java. Approval of the plan of development was received in December 2014 and front-end engineering and design was completed in 2015 together with geophysical and geotechnical surveys at the platform site, along the proposed platform-to-shore pipeline route and at the onshore receiving terminal location. Negotiations are continuing for a gas offtake agreement for a plateau production of approximately 70 mmcfd.

In parallel with the Indonesian gas projects, we are also working on two oil developments in the Gulf of Thailand – the Apsara oil field in Block A offshore Cambodia and the Rossukon oil field in G6/48 to the north of G10/48 in Thai waters.

Technical and fiscal terms for the KrisEnergy-operated Apsara oil development in Cambodia Block A have been agreed with the Cambodian authorities. Documentation is being formalised and first oil is targeted approximately 24 months after final investment decision is declared.

The *Key Gibraltar* jack-up rig was primarily contracted for the Wassana development drilling program, however an option to extend the rig contract at a favourable day rate provided the opportunity to drill four exploration wells in G6/48 and one in G10/48.

For the Rossukon series of wells in G6/48, one well and one sidetrack well were drilled from each of two surface locations. Each well intersected net oil and/or gas pay of between 106 feet true vertical depth ("TVD") and 148 feet TVD. Based on the drilling results and data from the original 2009 Rossukon discovery well, an application for a production licence was submitted in June 2015 and was approved by the Thai authorities in November 2015. Work is underway on a 3D reservoir model prior to the joint-venture partners finalising the Rossukon development concept.

The fifth well in the Gulf of Thailand, Rayrai-1, was drilled in G10/48 about 2.25 km north of the Niramai oil discovery made in 2009 and intersected approximately 50 feet TVD of net oil-bearing sandstones. Studies are now underway for a potential satellite oil development to the Wassana field.

2015 SEISMIC SUMMARY

COUNTRY	BLOCK	LOCATION	PROGRAM
Bangladesh	SS-11	Bay of Bengal over Bengal Fan	3,146 km offshore 2D seismic
Indonesia	Udan Emas	West Papua over Bintuni Basin	300 km land transition 2D seismic
Vietnam	Block 120	Quang Ngai Graben into Phu Khan Basin	575 sq. km offshore 3D seismic

2015 WELL SUMMARY

BLOCK	WELL NAME	MEASURED DEPTH (FEET)	TVDSS[1] (FEET)	RESULT
G6/48	Rossukon-2	5,460	– 4,924	69 feet TVD net oil-bearing sandstones/37 feet TVD net gas-bearing sandstones
	Rossukon-2ST	7,270	– 5,263	40 feet TVD net oil-bearing sandstones/100 feet TVD net gas-bearing sandstones
	Rossukon-3	7,497	– 6,235	75 feet TVD net oil-bearing sandstones/49 feet TVD net gas-bearing sandstones
	Rossukon-3ST	6,645	– 4,500	85 feet TVD net oil-bearing sandstones/63 feet TVD net gas-bearing sandstones
G10/48	Rayrai-1	6,382	– 5,281	50 feet TVD net oil-bearing sandstones
Sakti PSC	Mustika-1	2,768	– 2,667	Moderately high CO_2 gas encountered in Tuban and Kujung I formations

[1] Total vertical depth subsea ("TVDSS")

Exploration—mapping for the future

In Indonesia, the Mustika-1 exploration well was drilled in December 2015 in the Sakti PSC in the East Java Sea. The Sakti PSC neighbours the Bulu PSC where we continue to advance the Lengo gas development and pursue gas aggregation opportunities. Mustika-1 encountered gas in the Tuban and Kujung-I formations, however initial wireline logs and subsequent analysis of gas samples confirmed a moderately high carbon dioxide composition. A review is underway of the remaining prospects and leads in the Sakti block.

The completion of a 300 km 2D land and transition zone seismic acquisition program in the remote Udan Emas PSC in West Papua marked a significant achievement after three years of socialisation with the local communities, detailed planning and 135 days of data recording from almost 6,000 shot holes. Our health and safety performance earned an award from the Ministry of Energy and Mineral Resources Republic Indonesia in recognition of zero LTIs during more than two million man-hours in the field. Work is ongoing to build the geological model from the seismic data, 12,210 sq. km of airborne gravity and magnetic data along with samples and measurements of the surface geology.

In line with licensing regulations governing the first exploration period, the Indonesian authorities approved in February 2016 the first relinquishment of 25.6% of the gross acreage of the Udan Emas PSC leaving a remaining area of approximately 4,044 sq. km.

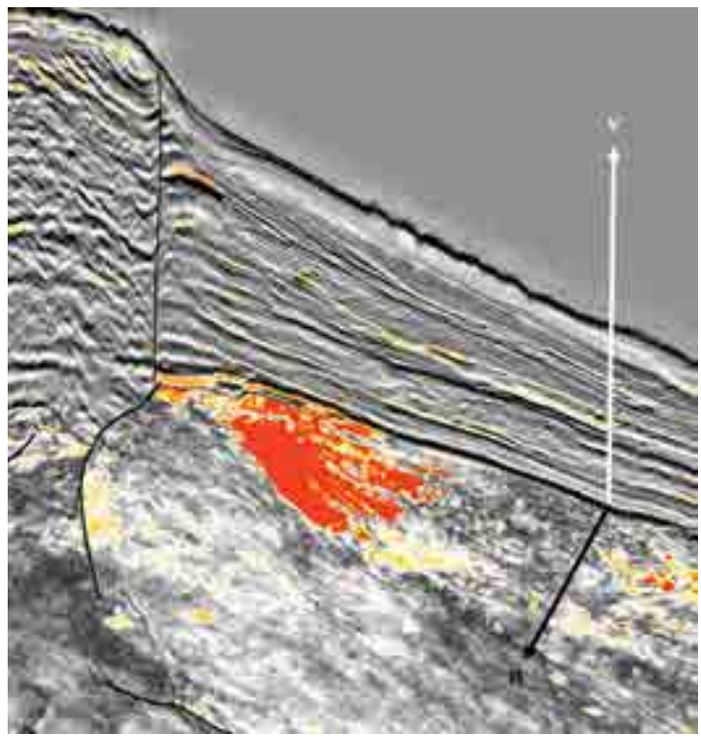
Outlook

Due to the sustained low commodity price environment, we have reduced our work program for 2016 to focus predominantly on maintaining and maximising production efficiencies. The planned capital expenditure budget of US$50.8 million is the lowest since the Company was established in 2009. Operations will centre on development drilling in the Bangora gas field around mid-year and our share of the costs of development drilling in the B8/32 & B9A producing complex.

Although capital expenditure will be curbed to a minimum with all discretionary spending deferred, exploration remains core to KrisEnergy's long-term growth strategy and our portfolio contains promising potential for exploration upside. We will continue exhaustive technical work to integrate data sets and to map and high-grade our prospects in order that they will be drill-ready once there is a recovery in the markets.

We have a series of prospects within the G6/48 and G10/48 licences where the Rossukon oil development and Wassana producing field are located, respectively. In Bangladesh, the 3,146 km 2D seismic data acquired in 2015 has revealed a range of leads and play types in the shallow water SS-11 exploration block. Planning is underway for the acquisition of 3D data likely next year.

We are also encouraged by the interpretation of 3D broadband seismic data acquired in 2014 in the Bala-Balakang PSC, formerly the Tanjung Aru PSC. Detailed mapping has identified a multitude of play types and bright spots, or local high amplitude seismic attribute anomalies, at numerous depths throughout the 502 sq. km area covered by the data.



A seismic chair display showing high amplitudes indicative of gas in a basin-floor fan in the Bala-Balakang PSC, formerly the Tanjung Aru PSC

Chris Gibson-Robinson
Executive Director, Director Exploration & Production
29 February 2016

The following reserves and contingent resources tables have been extracted from the qualified person's report dated 31 December 2015 ("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. at, 83 Clemenceau Avenue, #10-05 UE Square, Singapore 239920 to request an appointment.

Reserves

	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	0.60	0.18	12	0.95	0.29	16	1.13	0.34	26	
Indonesia										
Block A Aceh PSC	–	–	–	5.29	2.20	100	6.49	2.70	100	Transfer from contingent resources
Thailand										
B8/32 & B9A	22.36	1.04	(23)	114.17	5.29	(8)	136.91	6.35	(8)	
G6/48	–	–	–	11.70	3.51	100	15.80	4.74	100	Transfer from contingent resources
G10/48	12.08	10.75	100	18.73	16.67	25	26.57	23.65	8	Decrease in working interest and transfer from contingent resources
G11/48	7.96	1.79	(19)	9.90	2.23	(22)	11.97	2.69	(27)	
GAS										
Bangladesh										
Block 9	207.64	62.29	10	373.45	112.03	6	440.55	132.16	16	
Indonesia										
Bulu PSC	–	–	–	357.85	152.09	–	418.35	177.80	–	
Block A Aceh PSC	–	–	–	381.91	159.13	100	378.11	157.54	100	Transfer from contingent resources
Thailand										
B8/32 & B9A	131.61	6.10	(10)	668.72	30.99	(6)	820.20	38.01	(7)	

Reserves are 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 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% probability that the quantities actually recovered will equal or exceed the estimate.

Probable reserves (together with 1P, "2P") are additional reserves which analysis of geoscience and engineering data indicate 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% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible reserves (together with 1P and 2P, "3P") are additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

1 mmbbl refers to millions of barrels

2 bcf refers to billions of cubic feet

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	0.47	–	10.28	5.37	–	18.08	9.45	–	
Indonesia										
Block A Aceh	0.21	0.09	(82)	0.85	0.35	(63)	2.42	1.01	(42)	Transfer to reserves
Kutai	–	–	–	0.09	0.05	–	0.15	0.08	–	
Thailand										
G6/48	–	–	–	–	–	(100)	–	–	(100)	Transfer to reserves
G10/48	1.35	1.20	167	2.50	2.23	(63)	5.08	4.52	(56)	Decrease in working interest and transfer to reserves
G11/48	1.79	0.40	(23)	2.52	0.57	(36)	23.31	5.24	(9)	
	(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	8.30	–	128.95	38.69	–	
Indonesia										
Block A Aceh PSC	742.70	309.46	(34)	1065.16	443.81	(28)	1559.27	649.69	(22)	Transfer to reserves
East Muriah PSC	–	–	–	19.70	9.85	–	48.87	24.43	–	
Kutai PSC	–	–	–	75.70	41.33	–	117.45	64.13	–	
Bala-Balakang PSC	–	–	–	110.51	93.93	–	155.81	132.44	–	Increase in working interest
Thailand										
G11/48	4.92	1.11	–	14.84	3.34	–	26.08	5.87	–	
G6/48	11.48	3.44	100	13.24	3.97	100	15.37	4.61	100	

Contingent resources are 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%.

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%.

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%.

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.

1 mmbbl refers to millions of barrels
2 bcf refers to billions of cubic feet


WESTSTAR

Financial Review


GAS

Financial Review

Kiran Raj

Chief Financial Officer

Against the challenging backdrop of rapidly falling commodity prices, we successfully executed on our stated development objectives. We brought on stream two new oil projects in the Gulf of Thailand, one of which, the Wassana field, is the Company's first operated development. We entered 2015 with uncertainty surrounding global oil prices and as such, set our primary focus to deliver on near-term growth.

We stayed within our planned 2015 capital expenditure budget and exercised vigilance on cost control, especially in corporate general and administrative expenses, which declined by one-third as we cut salaries and headcount and lowered spending on consultancy fees.

As expected in this protracted depressed oil price environment, evaluation of our oil and gas assets and oil inventory were a key focus in preparing and delivering the 2015 audited financial results. Following rigorous stress testing of our portfolio under various oil price sensitivities, we recorded impairments over our Thai producing assets of US$69.9 million and, as a result of a lowering of near- and medium-term price assumptions, we wrote-down US$17.7 million on crude oil inventory. The diversification in our portfolio of oil and gas assets meant that asset impairments amounted to less than 8.1% of our total E&P asset portfolio.

Managing our capital structure and asset portfolio remains paramount to ensure we have funding flexibility and liquidity. In support of this, we farmed-out 11.0% working interest in G10/48, divested marine assets associated with the Wassana field, and increased our 2P reserves 49.2% to 105.9 mmboe. In addition, we successfully completed a consent solicitation exercise for the 2017 Notes and 2018 Notes and undertook a rights issue.

Revenue

Higher average daily production volumes as a result of new production from the Wassana and Nong Yao oil fields supported revenues. Audited consolidated revenue for 2015 decreased 19.7% to US$60.2 million (2014: US$74.9 million), whereas the average realised sales prices for oil and gas dropped 60.2% and 23.3% respectively, following the downturn in the global commodity cycle.

The 27.3% increase in production to an average 9,692 boepd in 2015 (2014: 7,612 boepd) helped cushion the impact of lower oil prices. Average Brent prices were 46.2% lower in 2015 at US$53.52/bbl (2014: $99.45/bbl).

Full-year production at the B8/32 & B9A oil and gas complex in the Gulf of Thailand and the Bangora gas field in Bangladesh remained stable compared with 2014.

FOR THE YEAR ENDED 31 DECEMBER	2015	2014
Sale of crude oil & liquids (US$ million)	40.7	49.8
Sale of gas (US$ million)	19.5	25.1
Revenue (US$ million)	60.2	74.9
Production volumes		
Oil & liquids (bopd)	3,492	1,396
Gas (mmcfd)	37.2	37.3
Total (boepd)	9,692	7,612
Average sales price		
Oil & liquids (US$/bbl)	40.18	100.93
Gas (US$/mcf)	4.45	5.80

Cost of sales

Cost of sales increased 72.9% to US$95.5 million in 2015 (2014: US$55.2 million), primarily due to higher operating costs, which increased to US$30.5 million in 2015 (2014: US$19.2 million) because of additional expenses associated with the start up of the G10/48 and G11/48 oil fields.

In line with the ramp up in production associated with Wassana and Nong Yao fields in the second half of the year, Group lifting costs for 2015 increased 30.2% to US$8.49/boe (2014: US$6.52/boe).

Depreciation, depletion and amortisation ("DD&A") expense in 2015 increased 47.6% to US$42.4 million (2014: US$28.7 million) due to the contribution to production from Wassana and Nong Yao. Non-cash expenses such as DD&A and a write down of inventory were US$60.0 million in aggregate and contributed to a gross loss of US$35.3 million.

FOR THE YEAR ENDED 31 DECEMBER	2015	2014
Cost of sales (US$ million)	95.5	55.2
Average lifting cost		
Oil, liquids and gas (US$/boe)	8.49	6.52
Operating costs (US$ million)	30.5	19.2
Total production (mmboe)	3.6	2.8

EBITDAX

EBITDAX increased 21.6% to US$37.2 million in 2015 (2014: US$30.5 million). Supporting the increase in EBITDAX was a reduction in corporate general and administrative expenses, which decreased 32.4% to US$12.1 million in 2015 (2014: US$17.9 million), through reductions in headcount and operating and capital expenditure.

FOR THE YEAR ENDED 31 DECEMBER (US$ million)	2015	2014
EBITDAX	37.2	30.5
Loss before tax	45.3	39.3
Tax expense	3.3	11.1
Loss after tax	**48.6**	**50.4**

Finance costs

Finance costs decreased 16.0% to US$19.5 million in 2015 (2014: US$23.2 million) due to financing fees incurred in 2014 related to the issuance of the 2017 Notes and 2018 Notes.

Loss before tax

We recorded a loss before tax of US$45.3 million in 2015 (2014: loss $39.3 million) as a result of lower gross profit due to higher DD&A expenses, asset impairments and an inventory write-down.

Capital expenditures & capital investments

In 2015, we spent US$59.5 million (2014: US$82.5 million) in capital expenditure for non-producing blocks. The successful appraisal well drilling program in the KrisEnergy-operated G6/48 concession accounted for US$7.2 million while seismic acquisition in the Udan Emas PSC accounted for US$20.9 million.

During the year, we saw the average cost of rigs and services fall by 20-40%, and in order to take advantage of the lower rates, we decided to drill one exploration well in the Sakti PSC offshore East Java. Our share of expenditure for the Mustika-1 well totalled US$10.0 million and we have now satisfied the well commitment for the PSC.

In January 2015, the acquisition of our working interest in the Block A Aceh PSC was approved and we paid the total of $50.4 million. Our share of capital expenditure in the development block was US$9.7 million for the full year.

Our share of capital expenditure for producing blocks was in aggregate US$165.2 million – US$12.1 million for B8/32 & B9A (52 development wells and the installation of one platform) and US$1.6 million in Block 9. Our share of expenditure at the newly producing G11/48 and G10/48 fields was US$34.4 million and US$126.5 million, respectively.

CAPITAL EXPENDITURE (US$ MILLION)

CAPEX BY COUNTRY (NET TO KRISENERGY)	2015 CAPEX BUDGET	ACTUAL 2015 CAPEX	2016 CAPEX BUDGET
CAPEX for non-producing assets	**68.9**	**59.5**	**24.8**
Bangladesh	2.0	2.1	0.4
Cambodia	4.9	2.0	1.8
Indonesia	51.5	46.0	14.6
Thailand	8.4	7.2	2.6
Vietnam	1.3	2.7	5.5
Other new ventures	0.8	–	–
CAPEX for producing assets	**176.7**	**165.2**	**26.0**
Bangladesh	5.4	1.5	7.9
Thailand[1]	171.3	163.7	18.0
TOTAL CAPEX	**245.6**	**224.7**	**50.8**

Excludes exploration expenses (such as dry hole costs, impairment and expenses relating to joint study agreements) and corporate general and administrative purposes. Our actual work program for 2016 may differ significantly from our provisional work program as set out above due to various factors, including but not limited to, changes in political, legislative and regulatory environment in countries where we have a presence, which may result in delays in obtaining governmental and regulatory approvals and availability of third-party services, equipment and materials

1 G10/48 and G11/48 were reclassified to producing assets following first production at the Wassana and Nong Yao fields, respectively in 2015

Loans & borrowings

Loans and borrowings as at 31 December 2015 amounted to US$304.6 million (2014: US$257.4 million), comprising the drawn amount of the 2014 RCF ("Revolving Credit Facility") of US$75.0 million and the 2017 Notes and 2018 Notes.

In November 2015, we launched a consent solicitation exercise in connection with the S$500 million multi-currency Medium Term Note Program. The exercise was to seek approval from noteholders of the 2017 Notes and 2018 Notes to amend the consolidated EBITDAX to consolidated interest expense ratio covenant. On 23 November 2015, the Company had received the necessary votes from noteholders. The consent solicitation exercise was completed and the amendments proposed pursuant to such exercise were approved by the noteholders on 4 December 2015.

Rights issue net proceeds

The rights issue was successfully completed on 11 August 2015 and generated gross proceeds of S$169.5 million (US$123.8 million). Net proceeds from the rights issue after deducting expenses for professional fees, underwriting and placement commissions and other related share issuance expenses were US$120.1 million (S$164.4 million). As of 31 December 2015, total rights issue proceeds of US$92.6 million had been utilised.

AS AT 31 DECEMBER 2015 (US$ million)	ALLOCATION OF PROCEEDS[1]	ACTUAL
Net rights issue proceeds	**120.1**	**120.1**
Utilisation		
Tranche 1: Capital expenditure (including exploration, appraisal and development of the Group's assets)	102.1	78.2[2]
Tranche 2: For general working capital	18.0	14.6[3]
Total utilisation of net proceeds		**92.6**
Net proceeds unutilised		27.5

1 Estimated net proceeds from the rights issue disclosed in the Offer Information Statement dated 13 July 2015 were US$123.2 million and the actual net proceeds received by the Company were US$120.1 million

2 Mainly attributed to our share of exploration and development costs in G11/48 and G10/48, and expenditure related to the exploration well in the Sakti PSC

3 General and administration expense and finance costs relating to the 2017 Notes, 2018 Notes and the 2014 RCF

Cash

Net cash flow from operating activities increased eight-fold to US$51.3 million in 2015 (2014: US$6.3 million), primarily due to an increase in trade payables and lower estimated tax payable in relation to B8/32 & B9A.

Net cash flow used in investing activities decreased 28.8% to US$245.2 million in 2015 (2014: US$344.6 million) as a result of capital expenditure and capital investment activities, which was offset by proceeds we received from a farm-out of an effective 11.0% working interest in G10/48 and from the sale of marine assets.

Net cash flow generated from financing activities increased 26.2% to US$174.4 million in 2015 (2014: US$138.2 million), mainly attributable to the receipt of net proceeds of US$120.1 million from the rights issue and proceeds from the bank borrowings.

FOR THE YEAR ENDED 31 DECEMBER (US$ million)	2015	2014
Net cash flows from operating activities	51.3	6.3
Net cash flows used in investing activities	245.2	344.6
Net cash flows from financing activities	174.4	138.2
Cash and bank balances	**29.4**	**51.3**

2016 financial outlook

As we close out the first quarter of 2016, we are comforted that our revenue will be supported by stable production, which has so far in 2016 doubled the 2015 rate and exceeded our expectations. Supplementing higher production and to support our profitability, we have implemented further cost reductions across all levels of the Group. In this environment we continue to rationalise our corporate expenses and hence, our overall general and administrative expenses and we continue to implement processes to reduce operating expenditure and take advantage of lower fuel prices and services to support profitability at our operated assets.

To provide funding flexibility, we have taken the necessary actions to reduce our 2016 planned capital expenditure to $50.8 million, down 77.4% from 2015, with over half of our work program and budget directed to our five producing assets.

The diversification of our portfolio between oil and gas assets, and various stages of the E&P life cycle, is allowing us to progress certain projects where economics are more robust under a stressed commodity price environment. Our partners and host governments have been responsive to our proposals to defer both discretionary and mandatory work commitments in operated blocks, while our partners in non-operated blocks have also taken initiatives to reduce operating costs and capital expenditure in the near-term.

Managing our capital structure will remain a priority as we prepare our balance sheet for a prolonged depression in the commodity cycle. A key priority for us in 2016 is to manage our cashflow and liquidity. We will continually examine ways to maximise our capital structure and access the debt and equity capital markets opportunistically. We have seen strong support from our shareholders, noteholders and banks through this time and we are grateful for their continued support as we execute on near-term objectives to deliver returns to our stakeholders.

Kiran Raj
Chief Financial Officer
29 February 2016

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 below sets out the material fiscal terms of our Bangladesh assets.

	BLOCK 9	SS-11
DMO 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 Petrobanglais subject to a further 1.0% discount.Price of gas sold to third parties shall be equalto 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 and up to 25,000 bopd	30.0%	25.0%	–
Portion over 25,000 and up to 50,000 bopd	25.0%	20.0%	–
Portion over 50,000 and 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 and up to 150 mmcfd	39.0%	34.0%	40.0%
Portion over 150 and up to 250 mmcfd	34.0%	27.5%	35.0%
Portion over 250 and up to 300 mmcfd	34.0%	27.5%	30.0%
Portion over 300 and up to 400 mmcfd	27.5%	22.0%	30.0%
Portion over 400 and up to 450 mmcfd	27.5%	22.0%	25.0%
Portion over 450 and up to 600 mmcfd	25.0%	17.5%	25.0%
Portion over 600 mmcfd	18.0%	15.0%	20.0%
PROFIT CONDENSATE/LIQUIDS (TO CONTRACTOR)			
Up to 3,000 boepd	35.0%	30.0%	–
Portion over 3,000 and up to 6,000 boepd	32.0%	27.0%	–
Portion over 6,000 and up to 10,000 boepd	28.0%	25.0%	–
Portion over 10,000 and up to 15,000 boepd	25.0%	20.0%	–
Portion over 15,000 boepd	20.0%	15.0%	–

	BLOCK 9		SS-11
	DURING COST RECOVERY	AFTER COST RECOVERY	
PROFIT OIL AND CONDENSATE/LIQUIDS (TO CONTRACTOR)			
Up to 5,000 boepd	–	–	45.0%
Portion over 5,000 and up to 12,500 boepd	–	–	42.5%
Portion over 12,500 and up to 25,000 boepd	–	–	40.0%
Portion over 25,000 and up to 40,000 boepd	–	–	35.0%
Portion over 40,000 and up to 65,000 boepd	–	–	30.0%
Portion over 65,000 and 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$1 million	US$3 million
		OIL	**OIL**
Upon daily average of 10,000 bopd for 30 consecutive days		US$1 million	US$0.5 million
Upon daily average of 20,000 bopd for 30 consecutive days		US$1 million	US$1 million
Upon daily average of 30,000 bopd for 30 consecutive days		US$1 million	US$2 million
Upon daily average of 40,000 bopd for 30 consecutive days		US$2 million	US$2.5 million
Upon daily average of 50,000 bopd for 30 consecutive days		US$2 million	US$3 million
Upon daily average of 100,000 bopd for 30 consecutive days		US$2 million	US$4 million
		GAS	**GAS**
Upon daily average of 75 mmcfd for 30 consecutive days		US$1 million	US$0.5 milion
Upon daily average of 150 mmcfd for 30 consecutive days		US$1 million	US$1 million
Upon daily average of 225 mmcfd for 30 consecutive days		US$1 million	US$2 million
Upon daily average of 300 mmcfd for 30 consecutive days		US$2 million	US$2.5 million
Upon daily average of 375 mmcfd for 30 consecutive days		US$2 million	US$3 million
Upon daily average of 450 mmcfd for 30 consecutive days		–	US$4 million
Upon daily average of 600 mmcfd for 30 consecutive days		US$5 million	US$6 million
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[1]

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

	BLOCK A	
ROYALTY	12.5% of production	
COST RECOVERY PETROLEUM	90.0% of production	
ALLOCATION OF REMAINING OIL (TO CONTRACTOR) (average annual production)	Up to 10,000 and up to 25,000 bopd	58.0%
	In excess of 10,000 – 25,000 bopd	53.0%
	Portion over 25,000 and up to 50,000	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 profit and 30.0% thereafter.	
PRODUCTION BONUS PAYMENT	None	
ANNUAL SURFACE RENTAL FEE	US$500 per sq. km of unrelinquished production area (once production permit is effective) and up to US$40 per sq. km of unrelinquished exploration area (expires once production permit is effective).	
MME OPTION	5.0% exercised on 15 November 2011 and completion to conclude effective date of production permit.	

[1] Negotiations with the Cambodian authorities on the terms of the production permit and Petroleum Agreement for Cambodia Block A are ongoing. The fiscal terms for Cambodia Block A may be amended as a result of the resolution reached with the Cambodia authorities

Indonesia

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

	BLOCK A ACEH	BULU	EAST MURIAH	EAST SERUWAY	KUTAI	SAKTI	BALA-BALAKANG	UDAN EMAS
FTP (OIL AND GAS):								
(as % of total petroleum production)	20.0%	10.0%	20.0%	20.0%	10.0%	20.0%	20.0%	20.0%
Effective Tax Rate	40.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%
DMO for oil	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
DMO for gas	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
DMO price for oil (% of market price)	15.0%	25.0%	25.0%	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%	100.0%	100.0%	100.0%
Pre-tax profit oil split to contractor	25.0%	35.7%	26.8%	26.8%	35.8%	41.7%	58.3%	58.3%
Pre-tax profit gas split to contractor	58.3%	62.5%	53.6%	53.6%	53.6%	58.3%	66.7%	66.7%
PRODUCTION BONUS PAYMENTS UPON CUMULATIVE PRODUCTION HAVING REACHED:								
25 mmboe	US$1 million	–	US$1 million	US$1 million	US$1 million	US$1 million	US$1 million	US$1 million
50 mmboe	US$2 million	US$500,000	US$2 million	US$1 million	US$2 million	US$1.5 million	US$1.5 million	US$1.5 million
75 mmboe	–	US$1 million	US$3 million	US$1 million	US$3 million	US$2 million	US$2 million	US$2 million
100 mmboe	US$4 million	–	–	–	–	–	–	–
125 mmboe	–	US$2 million	–	–	–	–	–	–
INDONESIAN PARTICIPATION OPTION	–	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
ACEH PARTICIPATION OPTION	10.0%	–	–	–	–	–	–	–
LOCAL COMMUNITY FUND CONTRIBUTION	1.0% of gross revenue	–	–	–	–	–	–	–

Thailand

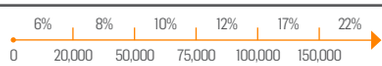
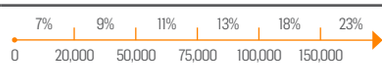
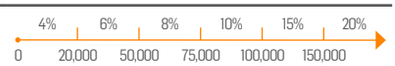
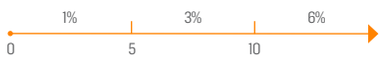
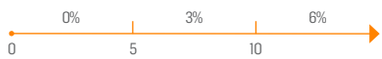
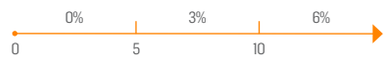
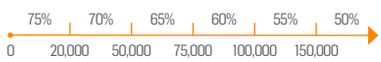
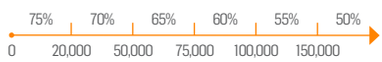
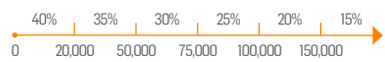
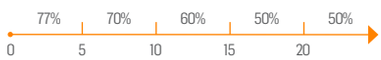
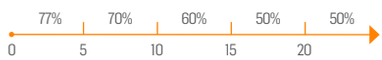
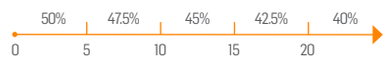
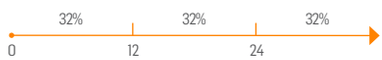
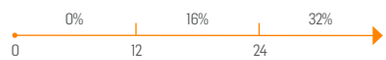
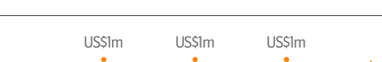
The table below sets out the material fiscal terms of our Thai assets.

	B9A		B8/32, G6/48, G10/48 & G11/48
ROYALTY (as % of the value of petroleum sold or disposed in each month)	12.5%	0 – 60,000 barrels	5.00%
		60,000 – 150,000 barrels	6.25%
		150,001 – 300,000 barrels	10.00%
		300,001 – 600,000 barrels	12.50%
		Over 600,000 barrels	15.00%
INCOME TAX RATE	50.0%		50.0%
ANNUAL SURFACE RESERVATION FEE	THB 4,000 per sq. km per year		None
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.	

		B8/32	G6/48	G10/48	G11/48
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%

Vietnam

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

	BLOCK 105	BLOCK 115/09	BLOCK 120
ROYALTY ON OIL (BOPD)			
ROYALTY ON GAS (MMCFD)			
COST RECOVERY LIMIT	70% of gross reserves	70% of gross reserves	70% of gross reserves
PRE-TAX PROFIT OIL SPLIT (TO CONTRACTOR)			
PRE-TAX PROFIT GAS SPLIT (TO CONTRACTOR)			
INCOME TAX RATE			
OIL EXPORT DUTY	10.0%	10.0%	4.0%
PRODUCTION BONUS PAYMENTS			
GENERAL			
Within 30 days of first commercial discovery	US$1 million	US$1 million	US$2 million
Within 30 days of first commercial production	US$1 million	US$1 million	US$2 million
OIL (BOPD) 30 consecutive days			
GAS (MMCFD) 30 consecutive days			
PetroVietnam option	20.0%	20.0%	20.0%

The table below sets out certain information regarding our oil and gas assets as at 29 February 2016.

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		11 March 2019[2]	–	–	4,475	Oil/Gas	PSC
CAMBODIA										
Block A	52.25[3]	Development pending & development unclarified	18 March 2002	See Note 4	See Note 4	–	–	4,709	Oil	Petroleum Agreement
INDONESIA										
Block A Aceh	41.6666	Near production & development unclarified	1 September 2011	31 August 2031	31 August 2031	–	–	1,680	Gas/ Condensate	PSC
Bulu	42.5	Near production	14 October 2003	13 October 2033	–	Lengo	13 October 2033	697	Gas	PSC
East Muriah	50.0	Development pending	13 November 2008	12 November 2038	13 November 2008 to 12 November 2018[5]	–	–	995	Gas	PSC
East Seruway	100.0	Exploration	13 November 2008	12 November 2038	13 November 2008 to 12 June 2016[5]	–	–	1,172	Oil/Gas	PSC
Kutai	54.6	Development pending	16 January 2007	15 January 2037	16 January 2007 to 15 January 2017[5]	–	–	944	Gas	PSC
Sakti	95.0	Exploration	26 February 2014	25 February 2044	26 February 2014 to 25 February 2020[5]	–	–	4,974	Oil/Gas	PSC
Bala-Balakang	85.0	Development unclarified	19 December 2011	18 December 2041	19 December 2011 to 18 December 2017[5]	–	–	3,143	Gas	PSC
Udan Emas	100.0	Exploration	20 July 2012	19 July 2042	20 July 2012 to 19 July 2018[5]	–	–	4,044	Gas	PSC
THAILAND										
B8/32	4.6345	Production	1 August 1991	31 July 2020[5]	–	Tantawan	31 July 2020[6]	1,992	Oil/Gas	Tax/ Royalty
						Benchamas South and Pakarong	31 July 2020[6]			
						Maliwan	31 July 2020[6]			
						North Jarmjuree	31 July 2020[7]			
						North Benchamas	31 July 2020[6]			
						Chaba	31 July 2020[6]			

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
B9A	4.6345	Production	17 July 2003	16 July 2041	–	Rajpruek	16 July 2041	80	Oil/Gas	Tax/ Royalty
G6/48	30.0	Near production	8 January 2007	See Note 6	8 January 2007 to 7 January 2021[4]	Rossukon	7 January 2036	566	Oil	Tax/ Royalty
G10/48	100.0[7]	Production & development unclarified	8 December 2006	See Note 6	8 December 2006 to 7 December 2020[4]	Wassana	7 December 2035[6]	4,696	Oil	Tax/ Royalty
G11/48	22.5	Production & development unclarified	13 February 2007	See Note 6	13 February 2007 to 12 February 2021[4]	Nong Yao	12 February 2036[6]	3,374	Oil	Tax/ Royalty
VIETNAM										
Block 105	51.0	Exploration	3 February 2010	2 February 2040	3 February 2016 to 2 February 2017[4]	–	–	7,192	Oil/Gas	PSC
Block 115/09	100.0	Exploration	31 March 2014	30 March 2044	31 March 2014 to 30 March 2018[4]	–	–	7,382	Oil/Gas	PSC
Block 120	33.33	Exploration	23 January 2009	22 January 2039	23 January 2009 to 22 January 2017[4]	–	–	6,869	Oil/Gas	PSC

Notes:

1 Each of our contract areas also holds exploration prospects and leads
2 The production permit for gas will be valid for 25 years with an extension period of up to five years
3 Assuming completion of the formal transfer of 5.0% interest in Cambodia Block A to the relevant government corporation as decided by the Cambodian MME, we will indirectly hold a 52.25% working interest in Cambodia Block A
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 KrisEnergy has an effective 89% working interest in G10/48

Our vision to build a sustainable upstream oil and gas company means one that will withstand the inevitable storms that buffet global energy markets.

Sustainability

Our vision to build a sustainable upstream oil and gas company means one that will withstand the inevitable storms that buffet global energy markets. We believe that in order to be successful, we must adopt values that allow us to reach high levels of performance whilst maintaining honesty, integrity and professionalism in all our business activities.

Our company is at a growth stage. As we expand and mature, the systems we use to monitor and manage our sustainability are also developing – for example, we are changing the way we benchmark health and safety incidents at work. We are committed to participating in initiatives that are beneficial to our local communities, including the clear communication of our operational activities within each community. While we strive to keep stakeholders fully informed of material issues relating to our business, we are also mindful of our responsibility to avoid inconsistency so as to ensure our disclosures are clear, offer real insight and are comparable over time.

KrisEnergy is committed to meaningful and transparent reporting. We welcome comments and suggestions on our announcements, website and annual reports from all stakeholders in our effort to deliver continuous improvement in the way in which we explain our business, our contribution to Asia's growth, the measures we take to mitigate the risks, and the impact we have on the communities and environments in which we operate.

Our people

We recognise that our people are our strongest asset and we place top priority on their wellbeing. We always seek out talented people where we operate and take great pride in our commitment to nurturing in-country the skills needed to build a successful and world-class upstream oil and gas industry.

We firmly uphold fair employment practices and are guided by the relevant legislation when establishing employee contracts and formulating employment policies. These policies are reviewed regularly and new policies are introduced following consultation with employees.

Since setting up our corporate office in Singapore in 2009, KrisEnergy has expanded into five other countries, Bangladesh, Cambodia, Indonesia, Thailand and Vietnam. We promote equal opportunity and the elimination of all forms of discrimination. Our goal is to maintain a healthy and enriching working environment in which all employees feel empowered and rewarded by a fulfilling career that allows them to realise their full potential, regardless of ethnicity or gender. We are proud that our approach of developing local talent has indirectly benefitted us in cultivating genuine relationships with local government authorities and has smoothed over numerous operational hurdles as we have evolved our business.

We periodically provide a range of operational training, such as safety courses, technical knowledge courses and more. We also carry out various emergency response drills regularly to ensure all employees remain vigilant and at the leading edge of health and safety, environmental stewardship and industry best practices.

Environment & security

We are in the business of extracting oil and gas. It is a fact that our operations affect the environment and the communities in which we operate. We make a serious and sustained effort to identify and understand the risks posed by our activities and take measures to mitigate our impact wherever possible.

We are committed to the continual improvement in our environmental performance through an internal management system that meets the ISO 14001 international standard. KrisEnergy has an integrated, group-wide system for reporting spillages of oil, dirty water and other pollutants. Last year, there were no incidents of any significance.

Restoration

The seismic survey in the Udan Emas PSC in West Papua required the removal of forest cover above the terrain to be mapped. As operator holding 100% working interest in the licence, we commenced reforestation in July immediately after seismic acquisition was complete by replanting thousands of saplings.

Health & safety

Training is a core part of our mission to ensure no one comes to harm doing their job. Health and safety is considered the highest priority operationally by KrisEnergy's management and we have put in place internal systems to monitor and continuously improve our performance.

We nurture a health and safety culture that runs throughout our organisation, one that emphasises individual responsibility at all levels. This commitment extends to our contractors and we actively assess and monitor their safety systems and preparedness, which may include providing training where needs have been identified.

In 2015, our Singapore office renewed its OHSAS 18001 certification, an international occupational health and safety management system standard overseen by SGS International Certification Services and accredited by the Swiss Accreditation Service. Our Dhaka office and onshore field operations received their OHSAS 18001 certification in November 2015 and our Jakarta office was awarded OHSAS 18001 certification in December 2014. Both Singapore and Dhaka locations are also ISO 14001 certified and accredited by the UK Accreditation Service.

Between January and December 2015, the KrisEnergy Group recorded 3,430,879 man-hours (see below pie-chart with breakdown) at operated assets with two LTIs during the Wassana development program. It is standard procedure that all LTIs occurring in licences that we operate are addressed through a root cause analysis, with corrective and preventive actions implemented, as well as opportunities for continual improvement.

While we will always seek to be incident-free in all areas of our operations, we are aware of the reality that our risk and responsibilities increase with the Company's growth. We are therefore migrating from measuring ourselves against absolute health and safety incidents to Lost Time Injury Frequency, the industry-standard benchmark measuring the rate of accidents over time.

Fire drill exercise on the *MOPU Ingenium* in the Gulf of Thailand

Zero lost-time injuries at the Udan Emas seismic operation

Our health and safety performance earned an award from the Ministry of Energy and Mineral Resources Republic Indonesia in recognition of zero LTIs during more than two million man-hours in the field.

3,430,879
WORKING MAN-HOURS

+94%
INCREASE ON 2014

Community

We take our responsibilities towards local communities seriously and are committed to ensuring that our impact is positive. KrisEnergy's community engagement centres on our core goal of giving a sustainable, long-term benefit to local people and focuses on three areas – education, healthcare, and social and environmental development. While most of our business is conducted offshore, we still recognise that we have an effect on the nearby areas onshore.

We believe that education empowers people, and therefore we support various educational programs across Southeast Asia, and charities that focus on the needs and development of children. We also engage with universities to help foster skills and build capacity in the oil and gas sector, sponsoring a small number of students through their studies or improving the quality of their course materials and learning environment or sponsoring geology field trips. In 2015, some beneficiaries include universities in Bangladesh, Cambodia, Indonesia and Vietnam.

We support healthcare workshops organised by local non-governmental organisations within areas in which we operate. The topics are wide-ranging and cover basic personal hygiene, blood grouping, preventive eye care and more. We believe that equipping members of the community with skills is a much more sustainable way for improving their quality of life.

Transparency & ethics

KrisEnergy is committed to transparency in our business dealings and to upholding the highest standards of integrity.

Employees who encounter a breach of our Code of Conduct have the option to report via an anonymous email to the appropriate manager. At present, the whistle blowing mechanism is not arms-length, though as the company expands, this will be reviewed from time to time.

We make no political donations and have a zero-tolerance policy towards illicit or undisclosed payments to government officials.

We strive for transparency in disclosing the fiscal terms and exploration and/or production periods of all our assets. These can be found on pages 30–35.

(Top) KrisEnergy together with PetroVietnam Technical Services Corporation, donated school supplies and clothing to improve the study and living standards of students at the Dak Nong school in Ha Giang, a rural province in northeast Vietnam

(Top middle) An inaugural "Mother & Child" event organised in a local Bangladeshi community to improve health and nutrition of expectant mothers and their children

(Bottom middle) Distribution of solar lamp and seismic awareness brochures in West Papua during our engagement with the local communities

(Bottom) Market scoping event supported by KrisEnergy to help female entrepreneurs in Sihanoukville in Cambodia grow their businesses. KrisEnergy plans to run similar programs in the community

Group Overview

Board Of Directors

As at 17 March 2016

Will Honeybourne (64)

Non-Executive Chairman

Bachelor of Science in Oil Technology, Imperial College, University of London; Member of the Society of Petroleum Engineers; Member of the Society of Exploration Geophysicists

Date of first appointment as Director: 5 October 2009 **Length of service as a Director (as at 31 December 2015):** 6 years 3 months **KrisEnergy Board Committee(s) served on:** Nominating Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd.; Archrock, Inc. *Other principal directorships:* Barra Holdings GP Ltd; First Reserve Asia Ltd (involuntary liquidation); First Reserve Energy Infrastructure GP Ltd; First Reserve Energy Infrastructure GP II Ltd; First Reserve GP XII Ltd; First Reserve GP XIII Ltd; FR Horizon GP Ltd; FR X Offshore GP Ltd; FR XI Offshore GP Ltd; FR XII Alternative GP Ltd.; KrisEnergy Holdings Ltd.; FR DGE III Alternative B GP Ltd; FREIF II Warehouse Alternative B GP, Ltd. **Major Appointments (other than directorships):** Managing Director of First Reserve **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Acteon Group Ltd; Exterran Holdings, Inc; FR Acteon Holdings Ltd; First Reserve International Ltd; KrisEnergy Pte Ltd; Red Technology Alliance; Petroleum Equipment Suppliers Association **Others:** Former Director of CNOOC Ltd (China National Offshore Oil Corporation)

John Koh (60)

Lead Non-Executive Independent Director

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

Date of first appointment as Director: 11 January 2013 **Length of service as a Director (as at 31 December 2015):** 3 years **KrisEnergy Board Committee(s) served on:** Audit Committee (Chairman); Nominating Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd.; NSL Ltd; Mapletree Industrial Trust *Other principal directorships:* Artfx Fine Art Services Ltd; Artpac Management Ltd; Bernard Quaritch Ltd; BMH Management Pte Ltd; Brandmine Properties Ltd;. Mapletree Industrial Fund Ltd; Mapletree Industrial Trust Management Ltd (as Trustee-Manager of Mapletree Industrial Trust); Mission Impossible Pte. Ltd; National Library Board; Worldwide Books Corporation **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Afa Management LLC; Arbutus International Ltd; China Lumena New Materials Corp; Easy Capital Ltd; Mandra Forestry Finance Ltd; Mandra Forestry Holdings Ltd; Mission Impossible International Ltd; Straits Capital Investments Ltd; School of the Arts; Genphar, Inc; Mapp Editions Ltd **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; Former founding partner of Wong Partnership

Keith Cameron (68)

Executive Director and Chief Executive Officer

Registered Chartered Accountant; Fellow of the Institute of Chartered Accountants of England and Wales; Member of the Canadian Institute of Chartered Accountants; Member of the Institute of Chartered Accountants, Alberta

Date of first appointment as Director: 5 October 2009 **Length of service as a Director (as at 31 December 2015):** 6 years 3 months **KrisEnergy Board Committee(s) served on:** Investment Review Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd. *Other principal directorships:* B Block Ltd; BEM Resources Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd.; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 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 Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte. Ltd; Puri Aircraft Ltd; SJ Production Barge Ltd **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** KrisEnergy Holdings Ltd; KrisEnergy Management Ltd; Mont D'Or Petroleum Limited **Others:** Former Chief Financial Officer and Vice President Finance for Gulf Indonesia Resources Ltd; formerly known as the Asamera Group of Companies; Former co-founder and Chief Executive Officer of Pearl Energy Ltd

Chris Gibson-Robinson (62)

Executive Director

Bachelor of Science and Associate Royal School of Mines Degree, Imperial College of Science and Technology, University of London; Master of Science in Marine Earth Science (Geology & Geophysics), University College of London; Chartered Geologist; Chartered Scientist; Fellow of the Geological Society of London; Member of the Geologists' Association of the United Kingdon; Member of the Indonesian Petroleum Association; Member of the South East Asia Petroleum Exploration Society; Member of the Petroleum Exploration Society of Great Britain

Date of first appointment as Director: 5 October 2009 **Length of service as a Director (as at 31 December 2015):** 6 years 3 months **KrisEnergy Board Committee(s) served on:** Nil **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd. *Other principal directorships:* B Block Ltd; BEM Resources Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 115) Ltd; KrisEnergy (Satria) Ltd; KrisEnergy (Song Hong 105) Ltd; KrisEnergy (Udan Emas) B.V.; KrisEnergy Holding Company Ltd; KrisEnergy International (Thailand) Holdings Ltd; KrisEnergy Management Ltd; KrisEnergy (Management Services) Ltd; KrisEnergy Oil & Gas (Thailand) Ltd; KrisEnergy Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte Ltd; SJ Production Barge Ltd **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** KrisEnergy Holdings Ltd; KrisEnergy Management Ltd **Others:** Former President and co-owner of Far East Exploration Co. Ltd, Former General Manager for Premier Oil (Halmahera) Ltd; Former Chief Technical Officer of Pearl Energy Ltd; Former Vice President, Operations and Vice President, New Ventures (Southeast Asia) and member of Aabar's senior executive team after Pearl Energy Ltd was acquired by Aabar

Richard Lorentz (60)

Executive Director

Bachelor of Science in Geology, Oklahoma State University; Master of Science in Geology, University of Philippines; Member of Indonesian Petroleum Association; Member of American Association of Petroleum Geologists; Member of Oklahoma Geological Society; Member of South East Asia Petroleum Exploration Society

Date of first appointment as Director: 5 October 2009 **Length of service as a Director (as at 31 December 2015):** 6 years 3 months **KrisEnergy Board Committee(s) served on:** Nil **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd. *Other principal directorships:* B Block Ltd; BEM Resources Ltd; CKR Resources (B.V.I.) Ltd; CKR Resources Pte Ltd; KrisEnergy (Apsara) Ltd; KrisEnergy (Asia) Ltd; KrisEnergy (Cambodia) Holding Ltd; KrisEnergy (Cambodia) Ltd; KrisEnergy (East Muriah) Ltd; KrisEnergy (Gulf of Thailand) Ltd; KrisEnergy G10 (Thailand) Ltd; KrisEnergy (Phu Khanh 120) Ltd; KrisEnergy (Song Hong 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 Pte Ltd; KrisEnergy Resources (Thailand) Ltd; KrisEnergy Marine Pte Ltd; Miclyn Express Offshore Ltd; SJ Production Barge Ltd **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Nil **Others:** Former Manager of the New Business Development department for Elf Aquitaine; Former New Ventures & Exploration Manager for Gulf Indonesia and Senior Production Geologist for Asamera (South Sumatra) Ltd.; Former Senior Field Geologist for Oriental Petroleum and Minerals Corp; Former Senior Exploration Geologist and Exploration Manager at Funk Exploration Inc.; Former Senior Explorationist at Anglo-Suisse (Pakistan) Inc.; Former Chief Business Development Officer and co-founder of Pearl Energy Ltd; Former Vice President New Ventures & Corporate Relations and member of Aabar's senior executive team after Pearl Energy Ltd was acquired by Aabar

Brooks Shughart (38)

Non-Executive Director

Bachelor of Business Administration in Finance, University of Texas at Austin

Date of first appointment as Director: 16 October 2012 **Length of service as a Director (as at 31 December 2015):** 3 years 2 months **KrisEnergy Board Committee(s) served on:** Audit Committee (Member); Investment Review Committee (Member); Remuneration Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd; Sabine Oil & Gas Corporation *Other principal directorships:* Amromco Holdings GP Ltd; Ascent Resources LLC; KrisEnergy Holdings Ltd; KIPP Houston Public Schools, Board of Trustees **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Sabine Oil & Gas Holdings LLC; KIPP Houston Public Schools, Executive Board **Others:** Former Director in the Mergers and Acquisitions Group of Credit Suisse

Chan Hon Chew[1] (51)

Non-Executive Director

Bachelor of Accountancy (Honours); Chartered Financial Analyst, Member of the Institute of Chartered Accountants Australia and Institute of the Singapore Chartered Accountants

Date of first appointment as Director: 17 March 2016 **Length of service as a Director (as at 31 December 2015):** Not applicable **KrisEnergy Board Committee(s) served on:** Investment Review Committee (member); Remuneration Committee (member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* Keppel Telecommunications & Transportation Ltd. *Other principal directorships:* Keppel Offshore & Marine Ltd, Keppel Land Ltd, Keppel Infrastructure Holdings Pte Ltd **Major Appointments (other than directorships):** Chairman of Keppel DCREIT Management Pte Ltd (Manager of Keppel DC Reit); Board of the Accounting Standard Council and Council of the Institute of Singapore Chartered Accountants **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Tiger Airways Holdings Limited, Singapore Aviation & General Insurance Company (Pte) Ltd and RCMS Properties Private Limited **Others:** Nil

[1] Appointed to the Board on 17 March 2016

Loh Chin Hua[2] (54)

Non-Executive Director

Bachelor Degree in Property Administration, Auckland University (Colombo Plan Scholarship); Presidential Key Executive MBA, Pepperdine University; CFA Charterholder; Registered Valuer from the New Zealand Institute of Valuers

Date of first appointment as Director: 9 July 2012 **Length of service as a Director (as at 31 December 2014):** 2 years 6 months **KrisEnergy Board Committee(s) served on:** Remuneration Committee (Member) **Present Directorships (as at 31 December 2014):** *Listed Companies:* Keppel Corporation Ltd; Keppel Land Ltd; Keppel Telecommunications & Transportation Ltd, KrisEnergy Ltd. *Other principal directorships:* Keppel Offshore & Marine Ltd; Keppel Infrastructure Holdings Pte Ltd; Alpha Investment Partners Ltd **Major Appointments (other than directorships):** Chief Executive Officer of Keppel Corporation Ltd **Past Principal Directorships held over the preceding 5 years (from 1 January 2010 to 31 December 2014):** AAJ Investment Pte Ltd; Alpha Investment Partners (BVI) Ltd; AIBJ Hero Pte Ltd; AIBJ Roppongi Pte Ltd; AIPJ Investment Pte Ltd; All Fortune International Ltd; Allenstand Ltd; Anderhill Ltd; ANOF Korea 1 Private Ltd; Antrohorne Ltd; Asia Real Estate Fund Management Ltd; AREFM (BVI); Ash Springs Ltd; Assibere Ltd; Brenspere Ltd; Bugis City Holdings Pte Ltd; Canyonwater Ltd; Caray Gardens Holdings Ltd; Chiba Investment Pte Ltd; Christus Ltd; Comprohorne Ltd; Core Plus Investment Pte Ltd; Daikanyama (CP) Investment Pte Ltd; Dapenso (CP) Investment Pte Ltd; Divine (AMT) Pte Ltd; Equity (CP) Pte Ltd; Ever Gain Logistics Pte Ltd; Fertile Crescent Ltd; Fusiongold Pte Ltd; Garrard Ventures Pte Ltd; Grathfield Ltd; Great Insight Investments Ltd; Greateast Investments Ltd; Highland Flow Pte Ltd; Hubville Co. Ltd; Japan Core Investment Pte Ltd; Kinetic (AMT) Ltd; Kephinance Investment Pte Ltd; Keppel Energy Pte Ltd; Keppel REIT Management Ltd (Manager of Keppel REIT); Kynson (AMT) Pte Ltd; Lavenson Investment Pte Ltd; Macro (AMT) Pte Ltd; Manesar (AMT) Pte Ltd; Matrix (CP) Investment Pte Ltd; Max Platinum Ltd; Myrick Investment Pte Ltd; Nordic (CP) Pte Ltd; Northern Tech Pte Ltd; Noxh Developments (Cecil) Pte Ltd; Numberspring Ltd; Omnibury Ltd; Pessiborge Ltd; Practical Asia Ltd; Preciousbud Ltd; Prestimorne Ltd; Prime Industrial Holdings Pte Ltd; Primiscorne Ltd; Pteris Global Ltd; Regal (1886) Pte Ltd; Rightbridge Ltd; Ristoria (AMT) Pte Ltd; Rochor Investment Ltd; Sacremorne Ltd; Samnorwood Ltd; Sanholpark Ltd; Sheung Wan (AMT) Pte Ltd; Shibuya (AMT) Pte Ltd; Shine City Investment Ltd; Shiodo (CP) Investment Pte Ltd; Solitaire (AMT) Pte Ltd; Sound Investments Ltd; Spellworth Ltd; Sperishorne Ltd; Tannehill Ltd; Trends (AMT) Pte Ltd; Trillington (AMT) Pte Ltd; Tsukiji (CP) Investment Pte Ltd; UL (CP) Investment Pte Ltd; Wallwrick Ltd; Zelkova (AMT) Pte Ltd **Others:** Former Managing Director at Prudential Investment Management Inc.; Former Head of European Real Estate Group in London of Government of Singapore Investment Corporation

[2] Resigned from the Board on 17 March 2016

Choo Chiau Beng (68)

Non-Executive Director

Bachelor of Science (First Class Honours), University of Newcastle upon Tyne (awarded Colombo Plan Scholarship to study Naval Architecture); Master of Science in Naval Architecture, University of Newcastle upon Tyne; Attended the Programme for Management Development at Harvard Business School; Member of Wharton Society of Fellows, University of Pennsylvania

Date of first appointment as Director: 9 July 2012 **Length of service as a Director (as at 31 December 2015):** 3 years 6 months **KrisEnergy Board Committee(s) served on:** Audit Committee (Member); Nominating Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd.; M1 Ltd. *Other principal directorships:* Keppel Care Foundation Ltd **Major Appointments (other than directorships):** Board Member of National Research Foundation, Prime Minister's Office; Member of Science and Engineering Research Council Board of A*Star; Member of the Investment Board of GIC Private Limited; Board member of Energy Studies Institute, National University of Singapore (NUS); Board and Council Member of American Bureau of Shipping; Chairman of Centre for Maritime Studies, NUS; Chairman of the Board of Governors of Raffles Institution; Member of Singapore University of Technology and Design's Board of Trustees **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Keppel Corporation Ltd; Keppel Offshore & Marine Ltd; Keppel Energy Pte Ltd; Keppel Land China Ltd; k1 Ventures Ltd **Others:** Nil

Duane Radtke (67)

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 (as at 31 December 2015):** 5 years 4 months **KrisEnergy Board Committee(s) served on:** Investment Review Committee (Chairman); Nominating Committee (Member); Technical Committee (Member); Remuneration Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* Devon Energy Corporation; KrisEnergy Ltd.; Sabine Oil & Gas Corporation **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 2011 to 31 December 2015):** Nil **Others:** Former President of Devon International Corporation; Former President and Chief Executive Officer of Dominion Exploration and Production

Jeff MacDonald (60)

Non-Executive Independent Director

Bachelor of Science (Hons) in Civil Engineering, Glasgow University

Date of first appointment as Director: 5 October 2009 **Length of service as a Director (as at 31 December 2015):** 6 years 3 months **KrisEnergy Board Committee(s) served on:** Nominating Committee (Member); Remuneration Committee (Chairman); Technical Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* KrisEnergy Ltd. *Other principal directorships:* Hansa Hydrocarbons Ltd **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Delta Energy Ltd; Remora Energy **Others:** Former Managing Director at Production Testing Services; Former Engineer and Project Manager at Conoco Inc.; Former Managing Director and Chairman at Blackwatch Petroleum Services Ltd; Former Managing Director of Highland Energy Ltd, Former Chief Executive at Caledonia Oil & Gas Ltd; Former Managing Director at First Reserve

Tan Ek Kia (67)

Non-Executive Independent Director

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; Professional Engineer, Board of Engineers, Malaysia; Chartered Engineer of Engineering Council; Member of Institute of Mechanical Engineers

Date of first appointment as Director: 11 January 2013 **Length of service as a Director (as at 31 December 2015):** 3 years **KrisEnergy Board Committee(s) served on:** Audit Committee (Member); Nominating Committee (Chairman); Technical Committee (Member) **Present Directorships (as at 31 December 2015):** *Listed Companies:* Keppel Corporation Ltd; KrisEnergy Ltd.; PT Chandra Asri Petrochemical Tbk; SMRT Corporation Ltd; Transocean Ltd *Other principal directorships:* 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 2011 to 31 December 2015):** 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

Alan Nisbet (65)

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 (as at 31 December 2015):** 1 year 7 months **KrisEnergy Board Committee(s) served on:** Audit Committee (Member); Investment Review Committee (Member); Remuneration Committee (Member) **Present Directorships (as at 31 December 2014):** *Listed Companies:* KrisEnergy Ltd.; Halcyon Agri Corporation Ltd *Other principal directorships:* Accounting and Corporate Regulatory Authority; Standard Chartered Bank (Singapore) Ltd; Ascendas Property Fund Management Pte Ltd **Major Appointments (other than directorships):** Nil **Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015):** Ascendas Pte Ltd; Deloitte & Touche Management Services Pte Ltd; Deloitte Consulting SEA Pte Ltd **Others:** Former Partner and Audit Leader in Deloitte & Touche LLP, Singapore

Keith Pringle (56)

Non-Executive Independent Director

Bachelor of Science (Hons) in Geology from Edinburgh University; Master of Science in Petroleum Engineering from Strathclyde University; Member of the Society of Petroleum Engineers

Date of first appointment as Director: 13 May 2014 **Length of service as a Director (as at 31 December 2015):** 1 year 7 months **KrisEnergy Board Committee(s) served on:** Audit Committee (Member); Investment Review Committee (Member); Remuneration Committee (Member); Technical Committee (Chairman) **Present Directorships (as at 31 December 2015):** *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 2011 to 31 December 2015):** Remora Energy; Delta Energy Ltd; KrisEnergy Ltd. **Others:** Former Independent Technical Advisor to KrisEnergy Ltd.

Management Team

As at 17 March 2016

Kiran Raj (43)

Chief Financial Officer

Mr. Raj joined KrisEnergy in 2013 and is a qualified Chartered Accountant with the Institute of Chartered Accountants in Australia. He has more than 17 years of investment banking and oil and gas experience in the Asia-Pacific region.

Mr. Raj started his career as a business analyst for a mid-sized Australian aerospace firm from 1994 until 1996. From 1996 until 2000, he was an integral senior member of the Corporate and Business Services division of international chartered accounting firm, Moore Stephens LLP. Mr. Raj moved to Singapore in 2000 and joined CLSA Merchant Bankers Limited ("CLSA") where he led the Southeast Asian investment banking execution business, including the initial public offering of Pearl Energy Ltd on the Singapore Exchange. At CLSA, Mr. Raj was the Director of Investment Banking and a member of the board of directors for CLSA Merchant Bankers Limited, the CLSA entity regulated by the Monetary Authority of Singapore.

In 2009, Mr. Raj founded, and was Chief Executive Officer for Brighton Capital Advisors, a corporate finance and advisory firm established in Singapore with a primary focus on the oil and gas sector. He has developed expertise within the oil and gas sector and has advised numerous independent and internationally recognised upstream companies throughout his career. Mr. Raj holds a Bachelor of Commerce majoring in Accounting and Finance from Monash University, Australia.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): KrisEnergy Management Ltd.

Kelvin Tang (41)

President Cambodia, Vice President Legal

Mr. Tang joined KrisEnergy in 2009 and is responsible for the legal and regulatory functions of the company. Since late 2014, Mr. Tang has taken on the additional role of President of KrisEnergy's activities in Cambodia. Prior to KrisEnergy, Mr. Tang was based in Abu Dhabi as General Counsel for Aabar Investments, having held the position of General Counsel and Company Secretary between 2005 and 2008 at Pearl Energy.

From 2003 until 2004, Mr. Tang was a Legal Associate for Wong Partnership LLP and Clifford Chance Wong (a joint law venture between Wong Partnership LLP and Clifford Chance Wong Pte Ltd). He was Associate Director (Legal) for Temasek Holdings Pte Ltd in 2002, and a Legal Associate in the Technology Practice Group of Rajah & Tann LLP between 2000 and 2002.

He holds a Bachelor of Law from the National University of Singapore and is an Advocate and Solicitor of the Supreme Court of Singapore. He is also a member of the Association of International Petroleum Negotiators.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): KrisEnergy (Ageng) B.V.; KrisEnergy (Andaman Timur) B.V.; KrisEnergy Asia Coöperatief U.A.; KrisEnergy Asia Holdings 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.

James Parkin (57)

Vice President Exploration

Mr. Parkin has been with KrisEnergy since inception and has more than 35 years of experience in the upstream oil and gas sector, of which he has spent over 25 years in Southeast Asia. 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 and Far East Exploration Co. Ltd. from 1997 until 1998. From 1998 until 2003, Mr. Parkin was a Senior Geologist and then Team Leader East Java at Gulf Indonesia/Conoco/ConocoPhillips.

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, the Indonesian Petroleum Association and the Petroleum Exploration Society of Great Britain.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): Nil

Brian Helyer (58)

Vice President Operations

Mr. Helyer has worked in the offshore oil and gas industry for over 35 years and looks after all aspects of project management for facilities construction, operations, maintenance and commissioning for KrisEnergy. Mr. Helyer joined the Company in 2010 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 block 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 14 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 2011 to 31 December 2015): Nil

Tim Kelly (56)

Vice President Engineering

Mr. Kelly has more than 30 years of experience in the upstream oil industry with the last 25 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 2011 to 31 December 2015): Nil

Mike Whibley (57)

Vice President Technical

Mr. Whibley is a geologist with over 35 years of management, operational and interpretive experience in exploration and development projects and new business development. He has been based in Southeast Asia for more than 20 years.

Prior to joining KrisEnergy in 2009, 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-Petro China 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 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.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): Nil

Chris Wilson (44)

Vice President Business Development

Mr. Wilson joined KrisEnergy in 2009 and is a strategist responsible for the origination and execution of corporate and asset acquisitions for the Group and in particular, the valuation of new business opportunities.

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. Chris 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 2011 to 31 December 2015): Panotech Pte Ltd

Tanya Pang (50)

Vice President Investor Relations & Corporate Communications

Ms. Pang has more than 25 years of experience in journalism and media/investor relations in the energy sector. She was initially a consultant to KrisEnergy and became a full-time employee of the Group in 2012.

In 2009, Ms. Pang was a consultant to companies including KrisEnergy, Schlumberger Business Consulting, Arawak Energy, Vitol and Atlantic Energy on a range of corporate communications, marketing, public relations and editorial matters. From 2008 until 2009, she was with Arawak Energy Ltd, a dual-listed upstream company on the Toronto Stock Exchange and the London Stock Exchange, as General Manager, Investor Relations based in London, United Kingdom. Ms. Pang was with Pearl Energy from 2005 until 2008, where she was responsible for investor relations and all internal and external communications. From 1994 until 2005, she was with Reuters news agency as a Journalist and worked on foreign assignments including five years as an International Correspondent in Oslo, Norway, and five years in Singapore as Editor-in-Charge, Energy for Asia-Pacific. She began her career as Deputy Editor on a monthly science journal before moving to Platts, the oil price benchmarking agency in 1992.

Ms. Pang holds a Bachelor of Science (Hons) in Chemistry from the University of Sussex and is a member of the South East Asia Petroleum Exploration Society.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): Nil

Edwin Bowles (62)

General Manager, Bangladesh

Mr. Bowles, a geologist, is an executive oil and gas industry professional with more than 35 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. He joined KrisEnergy in 2014.

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.

Edwin 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 2011 to 31 December 2015): RJ Energy Ltd; SAER Ltd

Malin Ros (50)

General Manager, Cambodia

Ms. Ros has more than 20 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 was appointed General Manager of KrisEnergy's Cambodian operations in October 2014 following the company's acquisition of Chevron Cambodia. 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 2011 to 31 December 2015): Nil

Basuki Kusmutarto (54)

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 2011 to 31 December 2015): Nil

Phattarin Jirapojaporn (40)

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 2011 to 31 December 2015): Nil

Nguyen Manh Huyen (66)

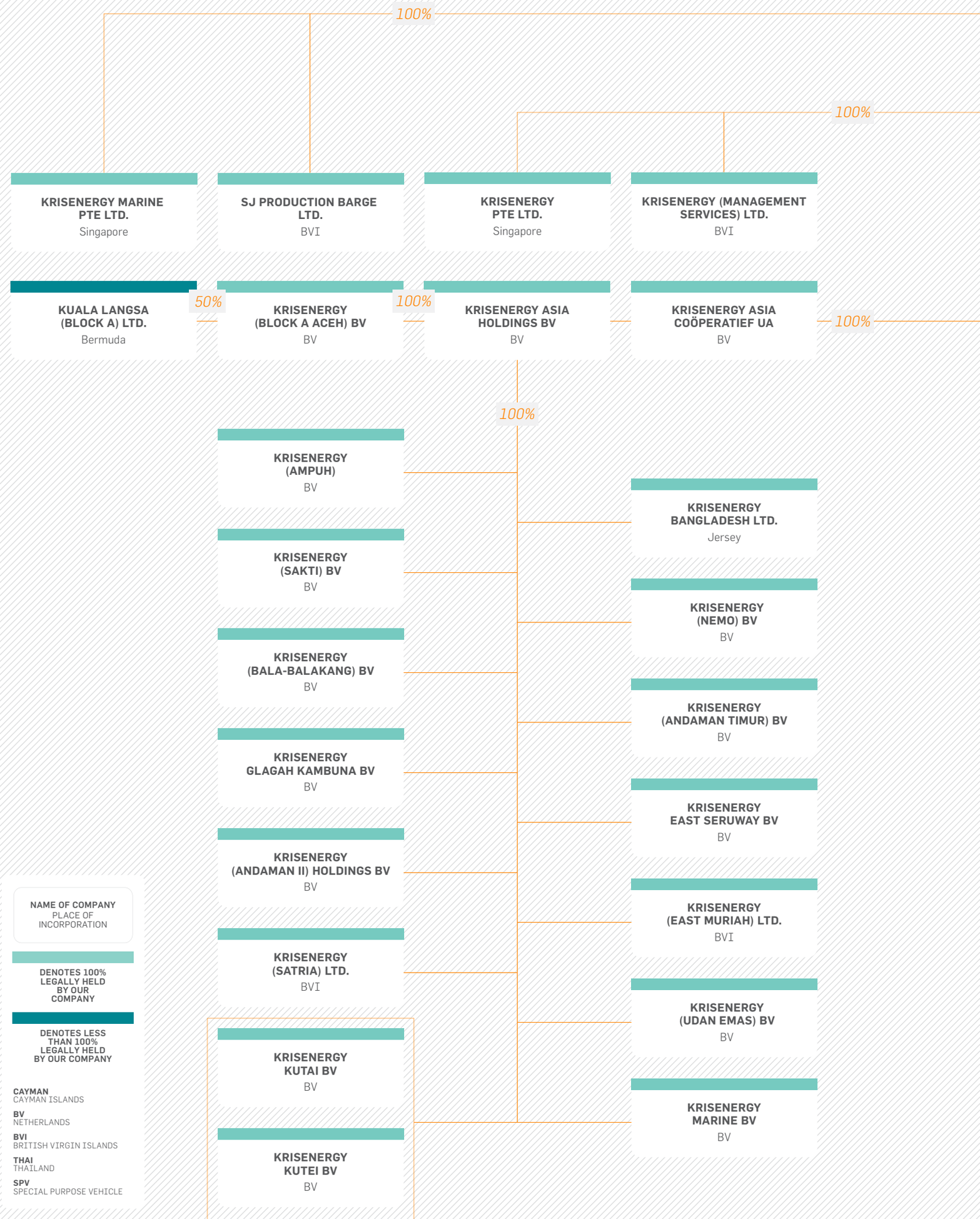
General Manager, Vietnam

Mr. Huyen has worked both as a geologist and a geophysicist. He has more than 40 years of experience, largely in Vietnam, but also in Southeast Asia, Middle East, North Africa and Russia. Mr. Huyen joined KrisEnergy in 2011.

His previous positions include Party Chief for seismic acquisition and Seismic Interpreter/ Researcher in geophysical methodology at Vietnam Petroleum Institute, Chief Geophysicist at American Red River Co., and at Petrovietnam Supervising Company (PVSC), New Ventures Project Manager at PVSC, and Exploration & Production Senior Manager at Petrovietnam Investment and Development Company (PIDC). Prior to joining KrisEnergy in 2011, Mr. Huyen was Project/General Manager for PIDC-Alger Company in Algeria and was General Manager for BachDang Petrovietnam Operating Company.

Mr. Huyen has a Bachelor of Science in Geophysics from the Institute de Petrol si Gas si Geology (University of Petroleum Geology), in Bucharest, Romania. He was a collaborator in Seismic Stratigraphy with the Moscow Geophysical Institute from 1983 until 1984. He is a member of the Vietnam Geophysical Association and is a Committee Member of the Vietnam Petroleum Association. He has a number of published reports and research work relating to petroleum exploration and production.

Past Principal Directorships held over the preceding 5 years (from 1 January 2011 to 31 December 2015): Nil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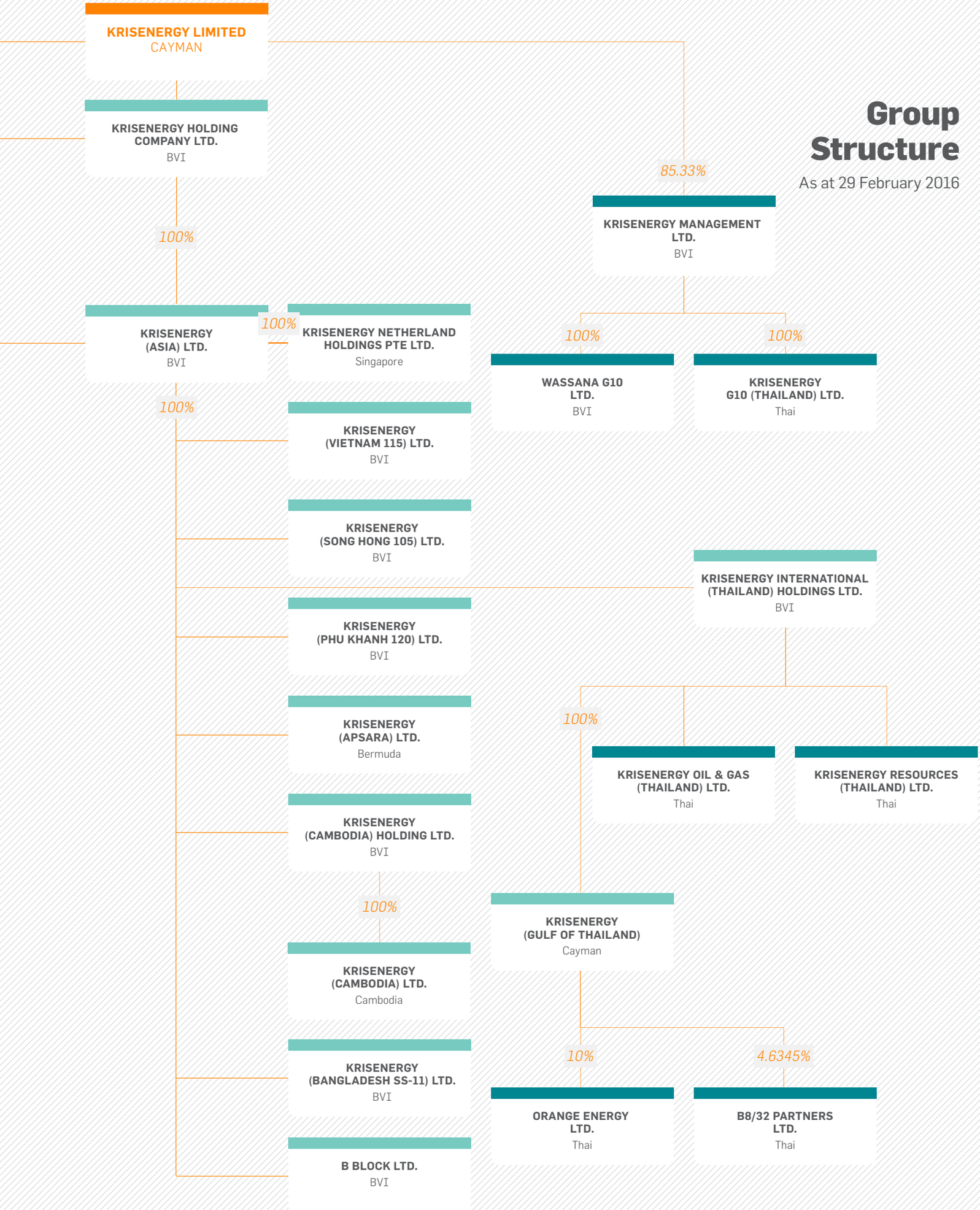
KRISENERGY MARINE PTE LTD.
Singapore
SJ PRODUCTION BARGE LTD.
BVI
KRISENERGY PTE LTD.
Singapore
KRISENERGY (MANAGEMENT SERVICES) LTD.
BVI
KUALA LANGSA (BLOCK A) LTD.
Bermuda
50%
KRISENERGY (BLOCK A ACEH) BV
BV
100%
KRISENERGY ASIA HOLDINGS BV
BV
KRISENERGY ASIA COÖPERATIEF UA
BV
100%
100%
KRISENERGY (AMPUH)
BV
KRISENERGY (SAKTI) BV
BV
KRISENERGY (BALA-BALAKANG) BV
BV
KRISENERGY GLAGAH KAMBUNA BV
BV
KRISENERGY (ANDAMAN II) HOLDINGS BV
BV
KRISENERGY (SATRIA) LTD.
BVI
KRISENERGY KUTAI BV
BV
KRISENERGY KUTEI BV
BV
KRISENERGY BANGLADESH LTD.
Jersey
KRISENERGY (NEMO) BV
BV
KRISENERGY (ANDAMAN TIMUR) BV
BV
KRISENERGY EAST SERUWAY BV
BV
KRISENERGY (EAST MURIAH) LTD.
BVI
KRISENERGY (UDAN EMAS) BV
BV
KRISENERGY MARINE BV
BV
NAME OF COMPANY
PLACE OF INCORPORATION
DENOTES 100% LEGALLY HELD BY OUR COMPANY
DENOTES LESS THAN 100% LEGALLY HELD BY OUR COMPANY
CAYMAN
CAYMAN ISLANDS
BV
NETHERLANDS
BVI
BRITISH VIRGIN ISLANDS
THAI
THAILAND
SPV
SPECIAL PURPOSE VEHICLE

Group Structure

As at 29 February 2016



Corporate Governance

The Board and management of KrisEnergy are committed to high standards of corporate governance, business integrity and professionalism. To this end, we confirm that we have complied in all material aspects with the principles and guidelines of the Code of Corporate Governance 2012 (the "2012 Code"). Deviations, if any, are appropriately explained within this corporate governance report. With specific reference to the 2012 Code, our corporate governance practices are set out on the following pages.

Board's Conduct of Affairs

Principle 1

Board responsibility

Accountable for our 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 our 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 these 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 ("CEO"), Directors and the succession planning process;
- overseeing a framework for evaluating adequacy of internal controls, risk management systems, financial reporting and compliance to safeguard shareholders' 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

The Audit, Nominating, Remuneration, Investment Review and Technical Committees are delegated the necessary authority by the Board to assist the Board with oversight of specific responsibilities. 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.

Meetings 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 without the presence of management at each Board meeting. Our Articles of Association ("Articles") permit telephonic attendance and conference for Board meetings.

The Board and Committees may also make decisions by way of circulating written resolutions.

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

Disclosed in Table 1 are the number of meetings held by the Board, Committees and Non-Executive Directors since 1 January 2015 to the end of the financial year under review, as well as the attendance of each Board member.

Table 1: Directors' attendance at Board and Committee meetings during the financial year under review

	BOARD MEETINGS[1]	COMMITTEE MEETINGS[1]				NON-EXECUTIVE DIRECTORS' MEETING (WITHOUT PRESENCE OF MANAGEMENT)
NAME OF DIRECTOR		AUDIT	NOMINATING	REMUNERATION	INVESTMENT REVIEW[2]	
Will Honeybourne	5	4[3]	4	4[3]	2[3]	4
John Koh	5	4	4	1[3]	2[3]	4
Keith Cameron	5	4[3]	2[3]	1[3]	2	–
Chris Gibson-Robinson	5	3[3]	1[3]	–	1[3]	–
Richard Lorentz	5	2[3]	1[3]	–	2[3]	–
Brooks Shughart	5	3	4[3]	4	2	4
Choo Chiau Beng	5	3	4	2[3]	1[3]	4
Loh Chin Hua[4]	5	1[3]	2[3]	3	–	3
Duane Radtke	5	4[3]	4	4	2	4
Jeff MacDonald	5	3[3]	4	4	1[3]	4
Tan Ek Kia	5	4	4	4[3]	2[3]	4
Alan Nisbet	5	4	3[3]	3	2	4
Keith Pringle	5	4	3[3]	4	2	4
Total no. of meetings held	**5**	**4**	**4**	**4**	**2**	**4**

Notes

1 Refers to meetings held/attended while each Director was in office
2 The Investment Review Committee was constituted in August 2015
3 By invitation
4 Resigned from the Board on 17 March 2016

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 at the meeting.

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, (a) acquisitions and disposals of material assets, (b) plans of development for petroleum assets, (c) the Group work program and budget, and (d) all material commitments to corporate and project financing from banks and financial institutions. This allows management to focus on their responsibilities for the day-to-day operation and administration of the Company.

Board induction

Newly appointed Directors will be sent induction letters detailing their duties and responsibilities. Management will also conduct 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 regularly informed of, and encouraged to attend, any appropriate and relevant courses which promote their professional development and encourage the highest standards of corporate governance and ethical conduct. In line with our policy, 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.

Board Composition and Guidance

Principle 2

Board size, composition and competency

To keep up 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 the 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 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.

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 which the 2012 Code provides 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 business relationships with the Company, or any related companies, and whether such relationships could interfere, or be reasonably perceived to interfere, with the exercise of the Director's independent judgement with a view to the best interests of the Company. The Board, taking into account the views of the Nominating Committee, considers the following Directors independent: John Koh, Duane Radtke, Jeff MacDonald, Tan Ek Kia, Alan Nisbet and Keith Pringle.

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 their 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.

Meeting of Directors without management: Formal sessions are arranged for Non-Executive Directors to meet after each scheduled Board meeting to discuss matters without the presence of management.

Other Committees

In addition to the Audit, Nominating and Remuneration Committees, the following Committees have been constituted to assist the Board in executing its duties:

- Investment Review Committee (recently constituted in August 2015)
- Technical Committee (constituted in February 2016 and meets when required)

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 Committee's structure and membership.

Investment Review Committee

The Investment Review Committee was formed in August 2015. It is chaired by Duane Radtke and comprises Keith Cameron, Brooks Shughart, Alan Nisbet, Keith Pringle and Chan Hon Chew. The Investment Review Committee comprises five Non-Executive Directors, one Executive Director and one consultant. The Investment Review Committee meets quarterly or when required.

The key responsibilities of the Investment Review Committee include:

- providing advisory support to management for all proposed investments of the Company;
- reviewing and providing approvals and recommendations to the Board for any major transactions which the Company proposes to undertake; and
- undertaking generally such other functions, duties and powers as may be required by the Board or the Board Committees from time to time.

Chan Hon Chew is the Chief Financial Officer of Keppel Corporation, an indirect controlling shareholder and was appointed to the Board on 17 March 2016.

Technical Committee

The Technical Committee is chaired by Keith Pringle and comprises Tan Ek Kia, Duane Radtke and Jeff MacDonald. The Technical Committee comprises four Independent Non-Executive Directors. The Technical Committee meets on an *ad hoc* basis only when requested by the Company.

The key responsibilities of the Technical Committee include:

- providing advisory support to management for technical matters as and when required;
- holding meetings with Company's technical management team at suitable junctures to review and advise on exploration and appraisal plans and activities, field development plans, technical evaluations on acreage or asset acquisitions, and health, safety and environment matters;
- providing the Board with updates on relevant technical matters as and when required; and
- undertaking generally such other functions, duties and powers as may be required by the Board or the Board Committees from time to time.

Chairman & CEO

Principle 3

Separation of the role of Chairman and CEO

A separation of roles and powers between the Chairman and the CEO ensures an appropriate balance of power, greater accountability and increased capacity of the Board for independent decision making. Will Honeybourne is our Non-Executive Chairman, and Keith Cameron is our CEO. Our Chairman is not related to our CEO.

Spearheading a high standard of corporate governance, our Chairman, with the aid of Directors, Company Secretaries and management, guides the Board to ensure its effectiveness in all aspects of its role. He sets the agenda and monitors the flow of information from management to the Board to ensure that all material information is provided in a timely manner for Directors to review and discuss. He encourages and promotes communication and constructive relations between the Board and management, and between Executive and Non-Executive Directors.

Our CEO manages and oversees the Group's business. The other Executive Directors and management provide assistance to the CEO in making strategic proposals to the Board. Pursuant to open and constructive Board discussion, the CEO formulates the plan to execute the agreed strategy and implements Board decisions.

Lead Independent Director

Our Lead Independent Director, John Koh, is appointed by the Board to direct the coordination of activities for Non-Executive Directors in instances where it would not be appropriate for the Chairman to serve in such capacity. Ensuring effective corporate governance measures are practised, the Lead Independent Director works closely with the Chairman and Board in the management of the affairs of the Company. The Independent Directors meet

periodically and the Lead Independent Director provides feedback to the Board after such meetings.

The Lead Independent Director is available to shareholders should they have concerns which have failed to be satisfactorily resolved by contact through the normal channels with the Chairman, CEO and Chief Financial Officer ("CFO").

Board Membership

Principle 4

Nominating Committee

The Nominating Committee is chaired by Tan Ek Kia and comprises Will Honeybourne, John Koh, Choo Chiau Beng, Duane Radtke and Jeff MacDonald. The Nominating Committee comprises entirely Non-Executive Directors, of which four out of six (including the Nominating Committee Chairman) are independent.

Key responsibilities of the Nominating Committee include:

- reviewing and recommending candidates for appointment to the Board and Board Committees, as well as candidates for senior management;
- developing a process for evaluation of the performance of the Board, Board Committees and Directors;
- reviewing and recommending nomination for re-appointment or re-election or renewal of appointment of the Directors;
- reviewing Board succession plans for Directors, in particular, the Chairman and the CEO;
- reviewing training and professional development programs for the Board;
- determining the independence of Directors; and
- reviewing the participation by each Independent Director in any competing business and taking into account such matters in the re-appointment, re-election or renewal of appointment of such Independent Director.

Recommendation 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. We have, 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 his responsibilities adequately. Noting that the time requirement of each directorship varies, the Nominating Committee believes that limiting the number of directorships a Director can hold is arbitrary. Instead, each Director provides to the Nominating Committee a confirmation of his ability to devote sufficient time and attention to the Company's affairs, having regard to all other commitments. The Nominating Committee is satisfied that all Directors have discharged their duties adequately from 1 January 2015 until the end of the financial year under review, and will continue to do so in the next financial year.

Alternate Directors

The Company does not have a practice of appointing Alternate Directors.

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 matrix of the existing Board. The Nominating Committee will draw on the resources of Directors' personal and business contacts and recommendations of candidates during this 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 section entitled "Board of Directors" on page 40 of this Annual Report for key information on our Directors. The Notice of Annual General Meeting sets out the Directors proposed for retirement and re-election at the AGM.

Board Performance

Principle 5

Board evaluation policy

An independent consultant 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 questionnaires for the evaluation process. Developed by incorporating the best practices in the market on Director, 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 results are collated by the independent consultant and presented to the Nominating Committee. The Nominating Committee then assesses the evaluation results and identifies main components for improvement and maps out key action steps, which are then recommended to the Board and Committees.

Access to Information

Principle 6

Complete, adequate and timely information

Board and Committee materials are distributed in advance and are easily 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. Any additional material or information requested by the Directors is promptly furnished. Matters of a highly sensitive nature may be tabled at the meeting or discussed without any papers being distributed. Management who provide 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, 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

Our 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 ensure 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 Singapore Exchange Securities Trading Limited ("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 our Company Secretaries are subject to the approval of the Board.

Independent professional advice

Subject to the approval of the Chairman, 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.

Remuneration Matters

Principle 7

Remuneration Committee

The Remuneration Committee is chaired by Jeff MacDonald and comprises Brooks Shughart, Chan Hon Chew[1], Duane Radtke, Alan Nisbet and Keith Pringle. The Remuneration Committee comprises entirely Non-Executive Directors, of which four of six (including the Remuneration Committee Chairman) are independent.

The key responsibilities of the Remuneration Committee include:

- reviewing and approving policy for determining the remuneration of executives including that of Executive Directors, CEO and other key management personnel ("Senior Management");
- reviewing the ongoing appropriateness and relevance of the executive remuneration policy and other benefit programs;
- considering, reviewing and approving and/or varying the entire specific remuneration package and service contract terms for Senior Management;
- considering and approving termination payments, retirement payments, gratuities, ex-gratia payments, severance payments and other similar payments to Board members and Senior Management;
- reviewing obligations arising in the event of termination of Senior Management's contracts of service;
- reviewing and approving the design of all option plans, stock plans and/or other equity-based plans;
- determining each year whether awards will be made under each of the equity-based plans;
- reviewing and approving each award as well as the total proposed awards under each plan in accordance with the rules governing each plan;
- reviewing, approving and keeping under review performance hurdles and/or fulfilment of performance hurdles of each of the equity-based plans;
- approving the remuneration framework (including Directors' fees) for Non-Executive Directors; and
- reviewing succession plans for Senior Management positions.

The Remuneration Committee assists 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. Please refer to Principle 9 "Disclosure on Remuneration" of this corporate governance report for further information on the Company's compensation philosophy.

[1] Chan Hon Chew was appointed to the Board on 17 March 2016 and Loh Chin Hua resigned from the Board on 17 March 2016

Level & Mix of Remuneration

Principle 8

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 the financial year under review, awards were granted under the KrisEnergy PSP at the discretion of the Remuneration Committee. Such share awards are conditional upon the achievement of predetermined performance targets over the performance period. These performance conditions include market capitalisation and reserves targets. As at the end of the financial year, certain share awards granted under the KrisEnergy PSP have been partially vested.

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. The fees payable to Non-Executive Directors are paid in cash and are subject to shareholders' approval at each AGM.

Basic fee

Our Non-Executive Directors' basic fee structure is as disclosed in Table 2[1]:

Table 2: Non-Executive Directors' Fees

NATURE	DESCRIPTION	RATE
		US$
Board Fees	Chairman Fee	$20,000 per annum
	Basic Retainer Fee	$50,000 per annum
	Lead Independent Director Fee	$10,000 per annum
Audit Committee Fees	Membership Fee	$10,000 per annum
	Chairman Fee	$10,000 per annum
Remuneration Committee Fees	Membership Fee	$10,000 per annum
	Chairman Fee	$10,000 per annum
Nominating Committee Fees	Membership Fee	$10,000 per annum
	Chairman Fee	$10,000 per annum

1 Please also refer to "Reduction in Non-Executive Directors' remuneration"

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$10,000 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.

Reduction in Non-Executive Directors' remuneration

For the financial year of 2016, due to the recent rapid decline in oil prices and the effect it has on the oil and gas industry, the Non-Executive Directors have proposed a 25% downward reduction in their total remuneration to aid the Company through these trying times. The Remuneration Committee and the Board have considered and approved such downward reduction and it will be effective as of 1 January 2016 to 31 December 2016 (or such other timing as agreed between the Non-Executive Directors and the Company).

Share awards and options

Non-Executive Directors are also 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 on Remuneration

Principle 9

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 Tables 3 and 4 below:

Table 3: Directors

REMUNERATION BANDS	SALARY INCLUDING CPF, IF ANY	BONUS / PROFIT-SHARING	ALLOWANCES & OTHERS	DIRECTORS' FEES	PERFORMANCE SHARES	TOTAL
	%	%	%	%	%	%
S$1,000,001 to S$1,250,000						
Keith Cameron	65	–	21	–	14	100
Chris Gibson-Robinson	65	–	21	–	14	100
Richard Lorentz	65	–	21	–	14	100
Below S$250,000						
Will Honeybourne	–	–	–	100	–	100
John Koh	–	–	–	100	–	100
Brooks Shughart	–	–	–	100	–	100
Choo Chiau Beng	–	–	–	100	–	100
Loh Chin Hua[1]	–	–	–	100	–	100
Duane Radtke	–	–	–	100	–	100
Jeff MacDonald	–	–	–	100	–	100
Tan Ek Kia	–	–	–	100	–	100
Alan Nisbet	–	–	–	100	–	100
Keith Pringle	–	–	–	100	–	100

Table 4: Senior Management

REMUNERATION BANDS	DESIGNATON	BASED / FIXED SALARY INCLUDING CPF, IF ANY	BONUS / PROFIT-SHARING	ALLOWANCE & OTHERS	PERFORMANCE SHARES	TOTAL
		%	%	%	%	%
S$750,000 to S$1,000,000						
Kiran Raj	Chief Financial Officer	65	–	21	14	100
James Parkin	Vice President Exploration	65	–	21	14	100
Brian Helyer	Vice President Operations	65	–	21	14	100
Tim Kelly	Vice President Engineering	65	–	21	14	100
Kelvin Tang	Vice President Legal	65	–	21	14	100

1 Resigned from the Board on 17 March 2016

We believe that 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 our 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 Directors or Senior Management.

Remuneration of employees who are immediate family members of a Director or our CEO

No employee of the Company and its subsidiaries is an immediate family member of a Director or the CEO.

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.

Accountability & Audit

Principle 10

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 media and analyst briefings. 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.

Audit Committee

Principle 12

Audit Committee

The Audit Committee is chaired by John Koh and comprises Brooks Shughart, Choo Chiau Beng, Tan Ek Kia, Alan Nisbet and Keith Pringle. The Audit Committee comprises entirely of Non-Executive Directors, of which four out of six (including the Audit Committee Chairman) are independent.

The key responsibilities of the Audit Committee include:

- reviewing all financial information and any public financial reporting with management and external auditors for submission to the Board;
- reviewing significant financial reporting issues and judgements so as to ensure the integrity of financial statements and any announcements relating to financial performance;
- reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from Management on difficulties which they have encountered with management in the course of their audit;
- reviewing with external and internal auditors, and reporting to the Board at least annually, the adequacy and effectiveness of the internal control system, including financial, operational, compliance and information technology controls;
- reviewing 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;
- reviewing at least annually, the adequacy and effectiveness of the internal audit function;
- reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
- reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- reviewing 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 have been put in place;
- assessing 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;
- reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure;
- commissioning and reviewing the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material;
- reviewing risk management policies and guidelines and monitoring compliance therewith;
- reviewing and approving all hedging policies and types of hedging instruments;
- reviewing whistle-blowing policies and arrangements;
- reporting to the Board the work performed by the Audit Committee in carrying out its functions;
- monitoring the investments in the customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management or have shareholding interests in businesses that are similar or related to the Company and making assessments on whether there are any potential conflicts of interest.

The Audit 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 Committee regularly meets with the external auditors and internal auditors, in each case without management's presence and at least once annually.

The Board is of the view that the Audit Committee members (including the Audit 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 Committee members.

External auditors

The Audit Committee 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 re-appointment of the external auditors is subject to shareholder approval at the AGM.

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

In the financial year under review, the Audit Committee held discussions with management and the external auditors regarding the accounting principles applied in the financial statements and any items that may affect the integrity of the financial statements. Subsequently, the Audit Committee recommended to the Board the release of the full-year financial statements.

The total fees paid to our external auditors, Ernst & Young LLP, are as disclosed in Table 5 below:

Table 5: Fees

	S$'000	% OF TOTAL FEES PAID
External auditor fees for the financial year under review		
Total Audit Fees	287	75
Total Non-Audit Fees[1]	96	25
Total fees paid	**383**	**100**

[1] Non-audit services provided by Ernst & Young LLP include tax filing, transfer pricing study and model review

We have complied with Rules 712 and 715 of the Listing Manual of SGX-ST in the appointment of our auditors.

Whistle-blowing policy

Clearly defined procedures have been established to encourage employees, customers or third parties to report malpractices and misconduct in the workplace. Concerns about possible improprieties in matters of financial reporting, fraudulent acts and other matters in breach of company policies can be raised confidentially and arrangements are in place for investigations of such matters and for appropriate follow-up action. These procedures aim to promote fairness and consistency in dealing with concerns made in good faith. There were no whistle-blowing reports made during the financial year under review.

Interested person transactions policy

We have 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 by, the Finance Department and reviewed by the Audit Committee. There were no interested person transactions for the financial year under review.

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 CEO, any Director, or controlling shareholder subsisting at the end of the financial year under review.

Risk Management & Internal Controls, Internal Audit

Principles 11 & 13

Risk management and internal controls

It is the responsibility of the Board to ensure that there are sufficient risk governance measures implemented in the Company. The Board is also responsible for ensuring that management maintains a sound system of risk management and 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 Committee and the Board on significant risks encountered in operations.

We have developed and implemented a Board Assurance Framework ("Framework"), which includes an enterprise risk management framework. The Framework acts as the platform for identification of significant and material risks, to measure 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. We have also developed a risk governance structure, which provides details on the roles and responsibilities for the Board and management (specifically, the Chief Risk Officer) in risk monitoring, escalation, mitigation and reporting.

We have established risk appetite statements with tolerance limits 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 Committee and the Board and are monitored on a quarterly basis. In addition, the Board has received assurance from the CEO and CFO 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 that we have effective risk management and internal control systems.

The Audit Committee, as delegated by the Board, has the responsibility to oversee our risk management framework and policies. Any material non-compliance or failures in internal controls and recommendations for improvements will be reported to the Audit Committee. The Audit 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 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, our Board with the concurrence of the Audit Committee is of the opinion that the Group's system of risk management and internal controls, addressing financial, operational, compliance and information technology risks, which is relevant and material to the Group's current business scope and environment, was adequate as at 31 December 2015. 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

KPMG has been appointed to act as the Group's internal audit function ("Internal Auditors"). It is responsible for executing the Internal Audit Plan as approved by the Audit Committee and reporting the findings and recommendations of such audit to the Audit Committee on a quarterly basis. The Internal Auditors' primary line of reporting is to the Chairman of the Audit Committee, although the function reports administratively to Executive Directors. All internal audit summary reports are submitted to the Audit Committee for consideration, with copies of these reports extended to the Chairman, Executive Directors (specifically the CEO) 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 Committee.

The Internal Auditors have unrestricted direct access to the Audit Committee and unfettered access to all of documents, records, properties and personnel. The Internal Auditor carries out its function according to the International Professional Practices Framework developed by the Institute of Internal Auditors.

The Audit Committee approves the hiring, removal, evaluation and compensation of the auditing firm to which the internal audit function is outsourced. The Audit Committee is also responsible for the review, at least annually, of the adequacy and effectiveness of the internal audit function.

Shareholder Rights & Responsibilities

Principle 14

We believe in having a robust governance culture to ensure that shareholders receive fair and equitable treatment. We recognise that shareholders should be entitled to equal information rights and we strive to provide adequate, timely and sufficient information pertaining to changes and updates in our business, that could have a material impact on the share price and value.

Shareholders whose names are registered in the CDP Register and the Register of Members are entitled to participate in, and vote at, our shareholders' meetings. Shareholders are informed of shareholders' meetings through notices published in newspapers and reports or circulars sent to all shareholders. 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 up to two 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 the shareholders' meetings.

We advocate shareholder participation and will hold our shareholders' meetings in a central location in Singapore. Shareholders will be able to proactively engage our Board and management on our business activities and financial performance.

Communication with Shareholders & Investors

Principle 15

We remain 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. We provide regular and relevant information regarding the Company's performance, progress and prospects to aid shareholders and investors in their investment decisions. Where possible, we hold regular investor forums to provide information about the Company and the prevailing industry climate and also provide investors an avenue to raise any queries with management. Briefing sessions are conducted for the media and analysts when quarterly financial results are released.

All press statements, financial results and material information are published on SGXNET and our website www.krisenergy.com, and where appropriate, through media releases. Our announcements and website provide contact details for investors in the event they wish to contact us.

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.

We also have a dedicated investor relations team to facilitate communications with shareholders, the investor community, analysts and the media.

No dividend policy

We do not have a fixed dividend policy. Taking into consideration factors including but not limited to our 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, we do not intend to pay dividends.

Conduct of Shareholder Meetings

Principle 16

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 be present at each AGM and other shareholders' meetings held by us, if any, to address shareholders' queries. We 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

We have 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 & Consolidated Financial Statements

The Directors present herein their report dated 17 March 2016, 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 2015.

1 | DIRECTORS

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

WILL HONEYBOURNE
Non-Executive Chairman

JOHN KOH
Lead Non-Executive Independent Director

KEITH CAMERON
Executive Director and Chief Executive Officer

CHRIS GIBSON-ROBINSON
Executive Director

RICHARD LORENTZ
Executive Director

BROOKS SHUGHART
Non-Executive Director

CHOO CHIAU BENG
Non-Executive Director

CHAN HON CHEW
Non-Executive Director

DUANE RADTKE
Non-Executive Independent Director

JEFF MACDONALD
Non-Executive Independent Director

TAN EK KIA
Non-Executive Independent Director

ALAN NISBET
Non-Executive Independent Director

KEITH PRINGLE
Non-Executive Independent Director

2 | AUDIT COMMITTEE

The Audit Committee comprises four independent Directors. Members of the Audit Committee are:

JOHN KOH
Chairman

TAN EK KIA

CHOO CHIAU BENG

BROOKS SHUGHART

ALAN NISBET

KEITH PRINGLE

The Audit Committee carried out its function in accordance with the Code of Corporate Governance 2012, including the following:

- reviewing all financial information and any public financial reporting with management and external auditors for submission to the Board;
- reviewing significant financial reporting issues and judgements so as to ensure the integrity of the financial statements of the Company and any announcements relating to the Company's financial performance;
- reviewing together with external auditors, their audit plan, audit report, management letter and the responses which the external auditors have received from management on difficulties which they have encountered with management in the course of their audit;
- reviewing with external and internal auditors and reporting to the Board at least annually the adequacy and effectiveness of the internal control system, including financial, operational, compliance and information technology controls (such review can be carried out internally or with the assistance of any competent third parties);
- reviewing with internal auditors, the program, scope and results of the internal audit and management's response to their findings to ensure that appropriate follow-up measures are taken;
- reviewing at least annually, the adequacy and effectiveness of the internal audit function;
- reviewing the scope and results of the external audit, and the independence and objectivity of the external auditors;
- reviewing with external auditors the impact of any new or proposed changes in accounting principles or regulatory requirements on the financial information;
- reviewing 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 interests have been put in place;
- assessing 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;
- reviewing filings with the SGX-ST or other regulatory bodies which contain financial information and ensuring proper disclosure;
- commissioning and reviewing the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringement of any law, rule and regulation which is likely to be material;
- reviewing risk management policies and guidelines and monitoring compliance therewith;
- reviewing and approving all hedging policies and types of hedging instruments;
- reviewing whistle-blowing policies and arrangements;
- reporting to the Board the work performed by the Audit Committee in carrying out functions;
- monitoring the investments in customers, suppliers and competitors made by Directors, controlling shareholders and their respective associates who are involved in the management of or have shareholding interests in similar or related business of the Company and making assessments on whether there are any potential conflicts of interests; and
- undertaking generally such other functions and duties as may be required by the Listing Manual of the SGX-ST and by amendments made thereto.

The Audit Committee has recommended to the Board of Directors the nomination of Ernst & Young LLP for re-appointment as external auditors at the forthcoming Annual General Meeting of the Company.

3 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.

4 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 2015	AS AT 1 JANUARY 2015 OR DATE OF	AS AT 31 DECEMBER 2015	AS AT 1 JANUARY 2015 OR DATE OF APPOINTMENT, IF LATER
Will Honeybourne	–	–	–	–
John Koh	142,000[1]	100,000	–	–
Keith Cameron	180,249	–	The aggregate of[2]: (i) 5,947,022 Shares; (ii) 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; and (iii) 1,349,057 PSP Awards	The aggregate of: (i) 4,415,285 Shares; (ii) 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; and (iii) 1,095,627 PSP Awards
Chris Gibson-Robinson	601,235	221,069	The aggregate of[3]: (i) 5,545,916 Shares; (ii) 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; and (iii) 1,349,057 PSP Awards	The aggregate of: (i) 4,208,216 Shares; (ii) 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; and (iii) 1,095,627 PSP Awards
Richard Lorentz	581,355	207,069	The aggregate of[4]: (i) 5,545,916 Shares; (ii) 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; and (iii) 1,349,057 PSP Awards	The aggregate of: (i) 4,208,216 Shares; (ii) 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; and (iii) 1,095,627 PSP Awards
Brooks Shughart	–	–	–	–
Choo Chiau Beng	–	–	–	–
Loh Chin Hua[5]	–	–	–	–
Duane Radtke	–	–	2,000,000[6]	1,615,008
Jeff MacDonald	500,000[7]	352,536	–	–
Tan Ek Kia	142,000	100,000	–	–
Alan Nisbet	–	–	–	–
Keith Pringle	243,308[7]	171,344	–	–

5 | DIRECTORS' RECEIPT & 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.

6 | KRISENERGY EMPLOYEE SHARE OPTION SCHEME & 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:

Jeff MacDonald
Chairman

Duane Radtke

Brooks Shughart

Chan Hon Chew

Alan Nisbet

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.

According to the Register of Directors' Shareholdings kept by the Company, there were no changes to any of the above-mentioned interests between the end of the financial year and 21 January 2016.

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.

Notes:

1 Held through nominee, DBS Nominees Pte Ltd

2 Keith Cameron's deemed interests as at 31 December 2015 comprised:
- (i) 401,106 Shares held in trust by Flamboyant Ltd for his benefit and 5,545,916 Shares held by CKR Resources (B.V.I.) Ltd ("CKR Resources"), of which he is a controlling shareholder
- (ii) Shares awarded to him under the KrisEnergy PSP ("MS-Awards") comprising 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, subject to certain performance conditions being met and other terms and conditions; and
- (iii) up to 1,349,057 Shares awarded to him under the KrisEnergy PSP subject to certain performance conditions being met and other terms and conditions

3 Chris Gibson-Robinson's deemed interests as at 31 December 2015 comprised:
- (i) 5,545,916 Shares held by CKR Resources, of which he is a controlling shareholder;
- (ii) Shares awarded to him under the KrisEnergy PSP comprising 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, subject to certain performance conditions being met and other terms and conditions; and
- (iii) up to 1,349,057 Shares awarded to him under the KrisEnergy PSP subject to certain performance conditions being met and other terms and conditions

4 Richard Lorentz's deemed interests as at 31 December 2015 comprised:
- (i) 5,545,916 Shares held by CKR Resources, of which he is a controlling shareholder;
- (ii) Shares awarded to him under the KrisEnergy PSP (MS-Awards) comprising 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, subject to certain performance conditions being met and other terms and conditions; and
- (iii) up to 1,349,057 Shares awarded to him under the KrisEnergy PSP subject to certain performance conditions being met and other terms and conditions

5 Resigned from the Board on 17 March 2016

6 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 (2.0%) and his wife (2.0%) and their two sons (48.0% each)

7 Held through nominee, Raffles Nominees Pte Ltd

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 5,230,332 Shares awarded to the Executive Directors of the Company. In addition, awards have been granted under the KrisEnergy PSP on the Listing Date to three Executive Directors and six 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 3.0% 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 3.0% of the issued ordinary share capital of the Company.

Since the commencement of the KrisEnergy PSP, PSP Awards comprising 7,752,407 Shares had vested, and were allotted and issued to employees, including 1,183,161 Shares to the Executive Directors as of the end of the financial year in review.

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 2015	BALANCE AS AT 31 DECEMBER 2015
19 JULY 2013 (MS-AWARDS)					
DIRECTORS					
Keith Cameron	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 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 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
Chris Gibson-Robinson	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 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 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
Richard Lorentz	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 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 3% of the issued share capital of the Company at the time when the conditions of the MS-Awards have been satisfied
OTHER EMPLOYEES	up to six-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 six-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 six-ninths of 3% 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					
Keith Cameron	321,208	214,138	–	214,139	107,070
Chris Gibson-Robinson	321,208	214,138	–	214,139	107,070
Richard Lorentz	321,208	214,138	–	214,139	107,070
OTHER EMPLOYEES	4,466,065	2,977,382	21,014	2,977,374	1,467,669
25 JUNE 2014					
DIRECTORS					
Keith Cameron	321,208	–	–	321,208	321,208
Chris Gibson-Robinson	321,208	–	–	321,208	321,208
Richard Lorentz	321,208	–	–	321,208	321,208
OTHER EMPLOYEES	749,487	–	–	749,487	749,487
31 DECEMBER 2014					
DIRECTORS					
Keith Cameron	560,280	–	–	560,280	560,280
Chris Gibson-Robinson	560,280	–	–	560,280	560,280
Richard Lorentz	560,280	–	–	560,280	560,280
OTHER EMPLOYEES	1,792,897	–	–	1,792,897	1,792,897

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 2015	BALANCE AS AT 31 DECEMBER 2015
17 MARCH 2015					
EMPLOYEES	647,325	215,776	–	–	431,549
9 NOVEMBER 2015					
DIRECTORS					
Keith Cameron	540,748	180,249	–	–	360,499
Chris Gibson-Robinson	540,748	180,249	–	–	360,499
Richard Lorentz	540,748	180,249	–	–	360,499
OTHER EMPLOYEES	9,991,230	3,376,088	–	–	6,615,142

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 or its associate;

(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.

7 | AUDITORS

Our auditors, Ernst & Young LLP, have expressed their willingness to accept re-appointment.

On behalf of the Board of Directors

KEITH CAMERON Director

CHRIS GIBSON-ROBINSON Director

17 March 2016, Singapore

Statement by Directors

WE, KEITH CAMERON AND CHRISTOPHER GIBSON-ROBINSON, 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 statement of financial position of the Group and the Company as at 31 December 2015, the statement 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 give a true and fair view of the financial position of the Group and of the Company as at 31 December 2015 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, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they fall due.

On behalf of the Board of Directors

KEITH CAMERON Director

CHRIS GIBSON-ROBINSON Director

17 March 2016, Singapore

Independent Auditor's Report

FOR THE FINANCIAL YEAR ENDED 31 DECEMBER 2015

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

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of KrisEnergy Ltd. ("the Company") and its subsidiaries (collectively, the "Group"), which comprise the statement of financial position of the Group and the Company as at 31 December 2015, the statement 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, and a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with International Standards on Auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements of the Group and the statement of financial position and statement of changes in equity of the Company are properly drawn up in accordance with the provisions of the International Financial Reporting Standards so as to give a true and fair view of the financial position of the Group and of the Company as at 31 December 2015 and the financial performance, changes in equity and cash flows of the Group and the changes in equity of the Company for the year ended on that date.

ERNST & YOUNG LLP

Public Accountants and Chartered Accountants
Singapore

15 March 2016

Consolidated Statement of Comprehensive Income

FOR THE FINANCIAL YEAR ENDED 31 DECEMBER 2015

	NOTE	2015	2014
		US$	US$
Revenue		**60,171,199**	**74,905,229**
Cost of sales		(95,494,556)	(55,236,207)
Gross (loss)/profit		**(35,323,357)**	**19,669,022**
Other income		110,777,899	9,330,854
General and administrative expenses		(33,696,980)	(35,718,914)
Other operating expenses		(67,871,371)	(9,983,883)
Finance income		289,750	577,251
Finance costs		(19,458,084)	(23,153,200)
Loss before tax	6	**(45,282,143)**	**(39,278,870)**
Tax expense	7	(3,291,691)	(11,091,626)
Loss for the year		**(48,573,834)**	**(50,370,496)**
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Exchange differences on translation of foreign operations		(232,955)	(164,523)
Items that will not be reclassified to profit or loss			
Re-measurement of defined benefit obligations		303,144	(139,139)
Total comprehensive income for the year		**(48,503,645)**	**(50,674,158)**
Loss for the year attributable to			
Owners of the Company		(41,675,825)	(50,370,496)
Non-controlling interests		(6,898,009)	–
		(48,573,834)	**(50,370,496)**
Total comprehensive income attributable to			
Owners of the Company		(41,605,636)	(50,674,158)
Non-controlling interests		(6,898,009)	–
		(48,503,645)	**(50,674,158)**
Loss per share attributable to owners of the Company (cents per share)			
Basic	6	(3)	(5)
Diluted	6	(3)	(5)

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

Consolidated Statement of Financial Position

AS AT 31 DECEMBER 2015

		GROUP		COMPANY	
ASSETS	**NOTE**	**2015** US$	**2014** US$	**2015** US$	**2014** US$
Non-current assets					
Exploration and evaluation assets	8	447,405,007	402,778,672	–	–
Oil and gas properties	9	415,068,053	136,334,779	–	–
Other property, plant and equipment	10	11,219,620	1,161,203	–	–
Intangible assets	11	33,182,972	91,452,905	–	–
Investment securities		216,000	–	–	–
Investment in subsidiaries	12	–	–	333,298,448	330,557,206
Other receivables	14	–	–	884,507,158	645,464,973
		907,091,652	**631,727,559**	**1,217,805,606**	**976,022,179**
Current assets					
Inventories	13	28,272,387	14,670,074	–	–
Trade and other receivables	14	66,226,269	65,165,491	–	–
Prepayments		2,507,550	1,545,274	151,501	126,755
Cash and bank balances	15	29,351,634	51,334,088	433,269	1,610,557
		126,357,840	**132,714,927**	**584,770**	**1,737,312**
Assets held for sale	16	–	64,986,883	–	–
		126,357,840	**197,701,810**	**584,770**	**1,737,312**
Total assets		**1,033,449,492**	**829,429,369**	**1,218,390,376**	**977,759,491**

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

EQUITY AND LIABILITIES	NOTE	GROUP 2015 US$	GROUP 2014 US$	COMPANY 2015 US$	COMPANY 2014 US$
Equity					
Share capital	17	1,867,564	1,309,955	1,867,564	1,309,955
Share premium	17	727,245,039	604,582,768	727,245,039	604,582,768
Other reserve	17	1,494,936	225,266	1,676,876	1,689,441
Accumulated losses		(228,523,677)	(187,150,996)	(21,433,747)	(19,760,492)
		502,083,862	**418,966,993**	**709,355,732**	**587,821,672**
Non-controlling interests		(6,833,794)	–	–	–
Total equity		**495,250,068**	**418,966,993**	**709,355,732**	**587,821,672**
Non-current liabilities					
Employee benefit liability	21	1,888,841	1,483,647	–	–
Loans and borrowings	19	304,571,912	257,440,512	229,571,912	247,440,512
Deferred tax liabilities	7	40,959,937	40,309,640	–	–
Provisions	20	48,472,869	38,602,143	–	–
Other payables	18	34,843,307	–	239,785,877	119,062,800
		430,736,866	**337,835,942**	**469,357,789**	**366,503,312**
Current liabilities					
Trade and other payables	18	31,911,859	27,393,025	3,349,350	3,770,137
Accrued operating expenses	18	38,015,365	20,191,470	782,472	275,728
Derivative liabilities	23	35,545,033	19,388,642	35,545,033	19,388,642
Withholding tax payable		734,860	561,305	–	–
Tax payable		1,255,441	5,091,992	–	–
		107,462,558	**72,626,434**	**39,676,855**	**23,434,507**
Total liabilities		**538,199,424**	**410,462,376**	**509,034,644**	**389,937,819**
Total equity and liabilities		**1,033,449,492**	**829,429,369**	**1,218,390,376**	**977,759,491**

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

Consolidated Statement of Changes in Equity

FOR THE FINANCIAL YEAR ENDED 31 DECEMBER 2015

	ATTRIBUTABLE TO OWNERS OF THE COMPANY						NON-CONTROLLING INTERESTS	TOTAL EQUITY
GROUP	**SHARE CAPITAL**	**SHARE PREMIUM**	**ACCUMULATED LOSSES**	**FOREIGN CURRENCY TRANSLATION RESERVE**	**EMPLOYEE SHARE OPTION RESERVE**	**GENERAL RESERVE**		
	US$	US$	US$	US$	US$	US$	US$	US$
Balance at 1 January 2015	**1,309,955**	**604,582,768**	**(187,150,996)**	**(1,464,175)**	**1,689,441**	**–**	**–**	**418,966,993**
Loss net of tax	–	–	(41,675,825)	–	–	–	(6,898,009)	(48,573,834)
Other comprehensive income								
Exchange differences on translation of foreign operations	–	–	–	(232,955)	–	–	–	(232,955)
Re-measurement of defined benefit obligations	–	–	303,144	–	–	–	–	303,144
Total comprehensive income for the year	**–**	**–**	**(41,372,681)**	**(232,955)**	**–**	**–**	**(6,898,009)**	**(48,503,645)**
Grant of equity-settled share transactions with employees	–	–	–	–	2,531,789	–	–	2,531,789
Vesting of equity-settled share transactions with employees	7,428	2,536,926	–	–	(2,544,354)	–	–	–
Disposal of ownership in interest in subsidiary, without loss of control	–	–	–	–	–	1,515,190	64,215	1,579,405
Issuance of Shares	550,181	123,785,875	–	–	–	–	–	124,336,056
Shares issuance expense	–	(3,660,530)	–	–	–	–	–	(3,660,530)
Balance at 31 December 2015	**1,867,564**	**727,245,039**	**(228,523,677)**	**(1,697,130)**	**1,676,876**	**1,515,190**	**(6,833,794)**	**495,250,068**

GROUP	**SHARE CAPITAL**	**SHARE PREMIUM**	**ACCUMULATED LOSSES**	**FOREIGN CURRENCY TRANSLATION RESERVE**	**EMPLOYEE SHARE OPTION RESERVE**	**TOTAL EQUITY**
	US$	US$	US$	US$	US$	US$
Balance at 1 January 2014	**1,307,693**	**602,938,278**	**(136,641,361)**	**(1,299,652)**	**527,847**	**466,832,805**
Loss net of tax	–	–	(50,370,496)	–	–	(50,370,496)
Other comprehensive income						
Exchange differences on translation of foreign operations	–	–	–	(164,523)	–	(164,523)
Re-measurement of defined benefit obligations	–	–	(139,139)	–	–	(139,139)
Total comprehensive income for the year	**–**	**–**	**(50,509,635)**	**(164,523)**	**–**	**(50,674,158)**
Grant of equity-settled Share transactions with employees	–	–	–	–	2,808,346	2,808,346
Vesting of equity-settled share transactions with employees	**2,262**	**1,644,490**	**–**	**–**	**(1,646,752)**	**–**
Balance at 31 December 2014	**1,309,955**	**604,582,768**	**(187,150,996)**	**(1,464,175)**	**1,689,441**	**418,966,993**

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

COMPANY	SHARE CAPITAL	SHARE PREMIUM	ACCUMULATED LOSSES	EMPLOYEE SHARE OPTION RESERVE	TOTAL EQUITY
	US$	US$	US$	US$	US$
Balance at 1 January 2015	**1,309,955**	**604,582,768**	**(19,760,492)**	**1,689,441**	**587,821,672**
Loss net of tax	–	–	(1,673,255)	–	(1,673,255)
Other comprehensive income	–	–	–	–	–
Total comprehensive income for the year	**–**	**–**	**(1,673,255)**	**–**	**(1,673,255)**
Grant of equity-settled share transactions with employees	–	–	–	2,531,789	2,531,789
Vesting of equity-settled share transactions with employees	7,428	2,536,926	–	(2,544,354)	–
Issuance of Shares	550,181	123,785,875	–	–	124,336,056
Shares issuance expense	–	(3,660,530)	–	–	(3,660,530)
Balance at 31 December 2015	**1,867,564**	**727,245,039**	**(21,433,747)**	**1,676,876**	**709,355,732**
Balance at 1 January 2014	1,307,693	602,938,278	(1,481,415)	527,847	603,292,403
Loss net of tax	–	–	(18,279,077)	–	(18,279,077)
Other comprehensive income	–	–	–	–	–
Total comprehensive income for the year	**–**	**–**	**(18,279,077)**	**–**	**(18,279,077)**
Grant of equity-settled share transactions with employees	–	–	–	2,808,346	2,808,346
Vesting of equity-settled share transactions with employees	2,262	1,644,490	–	(1,646,752)	–
Balance at 31 December 2014	**1,309,955**	**604,582,768**	**(19,760,492)**	**1,689,441**	**587,821,672**

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 2015

OPERATING ACTIVITIES	NOTE	2015 US$	2014 US$
Loss before tax		(45,282,143)	(39,278,870)
Adjustment to reconcile loss before tax to net cash flows			
Depreciation, depletion and amortisation		43,196,999	29,141,379
Decommissioning provisions	20	8,951,487	14,218,838
Employee defined benefit		708,338	226,224
Equity-settled share transactions with employees	22	2,531,789	2,808,346
Excess of fair value of identifiable net assets acquired over consideration paid	4	(42,993,442)	–
Gain on disposal of assets	16	(24,558,714)	–
Impairment loss on exploration and evaluation assets	8	584,309	–
Impairment loss on oil and gas properties	9	11,116,545	–
Impairment loss on intangible assets	11	58,177,765	–
Loss on disposal of other plant and equipment		1,140	12,508
Loss on disposal of investment securities		–	182,057
Net fair value (gain)/loss on financial instruments		(2,151,703)	9,097,672
Finance cost		18,538,845	22,511,127
Unwinding of discount on decommissioning provisions	20	919,239	642,073
Interest income		(289,750)	(577,251)
Operating cash flows before changes in working capital		**29,450,704**	**38,984,103**
Changes in working capital			
Increase in inventories		(3,465,666)	(7,504,782)
Increase in trade and other receivables		(664,678)	(4,713,161)
Increase/(decrease) in trade and other payables		37,162,383	(278,270)
Cash flows from operations		**62,482,743**	**26,487,890**
Interest received		289,750	577,251
Interest paid		(4,998,038)	(7,566,799)
Taxes paid		(6,473,965)	(13,179,388)
Net cash flows from operating activities		**51,300,490**	**6,318,954**

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

	NOTE	2015	2014
INVESTING ACTIVITIES		US$	US$
Additions to exploration and evaluation assets	8	(104,342,738)	(82,553,592)
Additions to oil and gas properties	9	(193,346,053)	(24,453,401)
Advances for acquisition	14	–	(4,152,697)
Expenditure on assets refurbishment		(21,370,227)	(8,986,883)
Proceeds from disposal of assets		110,000,000	–
Proceeds from disposal of ownership of interest in subsidiary		20,111,846	–
Proceeds from disposal of other plant and equipment		–	7,486
Purchase of other plant and equipment		(5,833,092)	(57,271,702)
Acquisition of subsidiaries, net of cash acquired	4	(50,456,505)	(167,216,439)
Net cash flows used in investing activities		**(245,236,769)**	**(344,627,228)**
FINANCING ACTIVITIES			
Proceeds from issuance of Shares		124,775,550	–
Proceeds from issuance of bonds	19	–	263,868,708
Proceeds from bank borrowings		189,000,000	135,000,000
Shares issuance expense	17	(3,660,530)	–
Repayment of bonds		–	(126,300,000)
Repayment of bank borrowings		(124,000,000)	(125,000,000)
Payment of bond interest		(13,962,569)	(9,567,573)
Decrease in short-term deposits		–	4,000,000
Decrease in cash collateralised	15	2,258,824	–
Increase in cash collateralised	15	–	(3,758,824)
Net cash flows from financing activities		**174,411,275**	**138,242,311**
Net decrease in cash and cash equivalents		**(19,525,004)**	**(200,065,963)**
Net effect of exchange rate changes		(198,626)	(168,470)
Cash and cash equivalents at 1 January		47,575,264	247,809,697
Cash and cash equivalents at 31 December	15	**27,851,634**	**47,575,264**

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

Notes to the Consolidated Financial Statements

FOR THE FINANCIAL YEAR ENDED 31 DECEMBER 2015

1 CORPORATE INFORMATION

KrisEnergy Ltd. (the "Company") was incorporated on 5 October 2009 as a limited liability company in Cayman Islands.

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 subsidiaries and joint arrangements are disclosed in Note 12 to the consolidated financial statements.

2 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").

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

The financial statements are presented in United States Dollars ("USD" or "US$"), except when otherwise indicated.

2.2 Basis of consolidation

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as at 31 December 2015. 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.

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 Group obtains control, and continue to be consolidated until the date when such control ceases.

Losses within a subsidiary are attributed to the non-controlling interest 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;
- 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 Changes in accounting policy and disclosures

Changes in accounting policies

The accounting policies adopted are consistent with those of the previous financial year except in the current financial year, the Group has adopted all the new and revised standards which are effective for annual financial periods beginning on or after 1 January 2015. The adoption of these standards did not have any effect on the financial performance or position of the Group.

2.4 Standards issued but not yet effective

The Group has not adopted the following standards applicable to the Group that have been issued but not yet effective:

DESCRIPTION	EFFECTIVE FOR ANNUAL PERIODS BEGINNING ON OR AFTER
IFRS 14 *Regulatory Deferral Accounts*	1 January 2016
Amendment to IFRS 10 *Consolidated Financial Statements*, IFRS 12 *Disclosure of Interests in Other Entities* and IAS 28 *Investments in Associates and Joint Ventures*	1 January 2016
Amendments to IFRS 11 *Joint Arrangement*	1 January 2016
Amendments to IAS 1 *Presentation of Financial Statements*	1 January 2016
Amendments to IFRS 10 *Consolidated Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*	1 January 2016
Amendments to IAS 16 *Property, Plant and Equipment* and IAS 38 *Intangible Assets*	1 January 2016
Amendments to IAS 27 *Separate Financial Statements*	1 January 2016
IFRS 15 *Revenue from Contracts with Customers*	1 January 2017
IFRS 9 *Financial Instruments*	1 January 2018
IFRS 16 *Leases*	1 January 2019

The Directors expect that the adoption of the standards above will have no material impact on the financial statements in the period of initial application, except for IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers* as indicated below.

IFRS 9 *Financial Instruments*

IFRS 9 introduces new requirements for classification and measurement, impairment of financial assets and hedge accounting. IFRS 9 is effective for annual periods beginning on or after 1 January 2018, with early application permitted. Retrospective application is required, but comparative information is not compulsory in the year of adoption. The adoption of IFRS 9 will have an effect on the classification and measurement of the Group's financial assets, but no impact on the classification and measurement of the Group's financial liabilities.

IFRS 15 *Revenue from Contracts with Customers*

IFRS 15 establishes a five-step model that will apply to revenue arising from contracts with customers. Under IFRS 15, revenue is recognised at an amount that reflects the consideration which an entity expects to be entitled in exchange for transferring goods or services to a customer. The principles in IFRS 15 provide a more structured approach to measuring and recognising revenue. The new revenue standard is applicable to all entities and will supercede all current revenue recognition requirements under IFRS. Either a full or modified retrospective application is required for annual periods beginning on or after 1 January 2017 with early adoption permitted. The Group is currently assessing the impact of IFRS 15 and plans to adopt the new standard on the required effective date.

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. The accounting policy for goodwill is set out in Note 2.10. 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 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

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 accounting policies 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 the 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.

2.7 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.

(i) 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.

(ii) Consolidated financial statements

For consolidation purpose, 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 interest and are not recognised in profit or loss.

2.8 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 value of the licence and property acquisition costs is written off through profit or loss. Upon recognition of proved reserves and internal approval for development, 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 asset is written off through profit or loss as a dry hole. 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.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, 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.

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.

2.9 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, 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 property 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

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 asset's 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 off. 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. When 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. Inspection costs associated with major maintenance programs are capitalised and amortised over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

2.10 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 value 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.

2.11 Impairment of non-financial assets

The Group assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when an annual impairment testing for an asset is required, the Group makes an estimate of the asset'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 value in use 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.

Impairment losses of continuing operations are recognised in profit or loss, except for assets that are previously revalued where the revaluation was taken to other comprehensive income. In this case, the impairment is also recognised in other comprehensive income up to the amount of any previous revaluation.

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 unless the asset is measured at revalued amount, in which case the reversal is treated as a revaluation increase.

2.12 Financial instruments

2.12.1 Financial assets

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.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not measured at fair value with changes in fair value recognised in profit or loss. These embedded derivatives are measured at fair value with changes in fair value recognised in profit or loss. Reassessment only occurs if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required.

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 derecognised or impaired, and through the amortisation process.

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 "pass-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 value 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.

2.12.2 Financial liabilities

Initial recognition and measurement

Financial liabilities 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 liabilities at initial recognition.

All financial liabilities are recognised initially at fair value plus in the case of financial liabilities not at fair value through profit or loss, directly attributable transaction costs.

Subsequent measurement

After initial recognition, 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.

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.

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 Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and on hand and cash collateralised.

2.14 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. 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.

2.15 Leases

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

2.16 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 Group recognises a decommissioning liability when it has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made.

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 value 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 value 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 exceeds 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.

The Group recognises neither the deferred tax asset in respect of the temporary difference on the decommissioning liability nor the corresponding deferred tax liability in respect of the temporary difference on a decommissioning asset.

Environmental expenditures and liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalised as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognised when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognised is the best estimate of the expenditure required. If the effect of the time value of money is material, the amount recognised is the present value of the estimated future expenditure.

2.17 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 value 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 value is amortised through profit or loss over the remaining term of the hedge using the effective interest rate 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.

The Group has cross currency swaps that are used as hedges for the exposure of changes in the fair value of its Multi-currency Medium Term Notes. See Note 23 for more details.

2.18 Non-current assets held for sale

Non-current assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Non-current assets are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use.

Other property, plant and equipment once classified as held for sale are not depreciated.

2.19 Revenue recognition

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, 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. Differences between oil lifted and sold and the Group's share of production are not significant. Where forward sale and purchase contracts for oil or natural gas have been determined to be for trading purposes, the associated sales and purchases are reported net.

The following criteria are also applicable to other specific revenue transactions:

Take-or-pay contracts

Under these contracts, the Group makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. These commitments contain protective (force majeure) and adjustment provisions. If a buyer has a right to get a 'make-up' delivery at a later date, revenue recognition is deferred and only recognised when the product is delivered, or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognised when the take-or-pay penalty is triggered.

2.20 Employee benefits

(a) 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.

(b) 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.

(c) 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 22.

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 22. 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 22.

(d) 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; and
- 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 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 as 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.

3 SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES & 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, 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 (Note 7, 8, 9, 11, 13 and 20)

Oil and gas properties are depreciated on a unit-of-production ("UOP") basis at a rate calculated by reference to total proved and probable developed and undeveloped reserves 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 appropriately qualified external 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. Commercial reserves are determined using estimates of oil in place, recovery factors and future commodity 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 calculation incorporates a range of oil prices from US$50 to US$90 (2014: US$60 to US$90) per barrel. The carrying amount of oil and gas properties at 31 December 2015 is shown in Note 9.

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, which include:

- The carrying value of exploration and evaluation assets, oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows
- Depreciation, depletion and amortisation charges and inventory cost may change where such charges are determined using the UOP method, or where the useful life of the related assets change
- Provisions for decommissioning may change where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities
- The recognition and carrying value of deferred tax assets may change due to changes in judgements regarding the existence of such assets and in estimates of the likely recovery of such assets

Exploration and evaluation expenditures (Note 8)

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.

Unit-of-production depreciation of oil and gas assets (Note 9)

Oil and gas properties are depreciated using the UOP method over total proved and probable developed and undeveloped hydrocarbon reserves. This results in a depreciation, depletion and amortisation charge proportional to the depletion of the anticipated remaining production from the asset.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the asset at which the asset is located. These calculations require use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total proved and probable reserves, or future capital expenditure estimates changes. Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including:

- The effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions; or
- Unforeseen operational issues.

Any changes in estimates are accounted for prospectively. A 1% difference in the forecast production based on total proved and probable reserves from management's estimates would result in approximately 0.1% (2014: 0.2%) variance in the net book value of oil and gas properties.

Recoverability of oil and gas assets (Note 9)

The Group assesses each asset or CGU (excluding goodwill, which is assessed annually regardless of indicators) 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 value in use. These assessments require the use of estimates and assumptions, such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGU.

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. Fair value for oil and gas assets is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU. Management has assessed its CGUs as being an individual asset, which is the lowest level for which cash inflows are largely independent of those of other assets.

Decommissioning costs (Note 20)

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 Group

assesses its decommissioning provision at each reporting date. 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. The expected timing, extent and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represent management's best estimate of the present value of the future decommissioning costs required. If the estimated pre-tax discount rate used in the calculation had been 1% higher than management's estimate, the carrying amount of the provision would have been US$2.6 million (2014: US$3.6 million) lower.

Fair value measurement (Note 26)

The Group measures financial instruments, such as derivatives, at fair value at each balance sheet date. The fair values of these financial instruments are disclosed in Note 26.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Taxes (Note 7)

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws, and the amount and timing of future taxable income. Given the wide range of international business relationships and the long-term nature and complexity of existing contractual agreements, differences arising between the actual results and the assumptions made, or future changes to such assumptions, could necessitate future adjustments to tax income and expense already recorded. 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. The amount of such provisions is based on various factors, such as experience of previous tax audits and differing interpretations of tax regulations by the taxable entity and the responsible tax authority. Such differences of interpretation may arise on a wide variety of issues depending on the conditions prevailing in the respective domicile of the Group companies.

Deferred tax assets are recognised for unused tax losses to the extent that it is probable that taxable profit will be available against which the losses can be utilised. Significant management judgement is required to determine the amount of deferred tax assets that can be recognised, based upon the likely timing and the level of future taxable profits together with future tax planning strategies.

The Group has US$49.0 million (2014: US$39.1 million) of tax losses available for carry forward. These losses relate to subsidiaries that have a history of losses, do not expire and may not be used to offset taxable income elsewhere in the Group. The subsidiaries have no taxable temporary differences nor any tax planning opportunities available that could partly support the recognition of these losses as deferred tax assets. On this basis, the Group has determined that it cannot recognise deferred tax assets on the tax losses carried forward. Further details on taxes are disclosed in Note 7.

Defined benefit plan (Note 21)

The cost of defined benefit pension plans and the present value of the pension obligations are determined using actuarial valuations. The actuarial valuation involves making various assumptions. These include the determination of the discount rates, expected rates of return of assets, future salary increases, mortality rates and future pension increases. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, defined benefit obligations are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date. The net benefit liability as at 31 December 2015 is US$1.9 million (2014: US$1.5 million).

In determining the appropriate discount rate, management considers the interest rates of high quality government bonds. The mortality rate is based on publicly available mortality tables for the specific country and is modified accordingly with estimates of mortality improvements. Future salary increases and pension increases are based on expected future inflation rates for the specific country. Further details about the assumptions used are provided in Note 21.

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.

(a) Impairment of intangible assets

As disclosed in Note 11 to the financial statements, the recoverable amounts of the CGUs which goodwill and other intangible assets have been allocated to are determined based on value in use calculations. The value in use calculations are based on a discounted cash flow models. The recoverable amount is most sensitive to the discount rate used for the discounted cash flow model as well as the expected cash inflows and the long-term oil prices assumptions used for extrapolation purposes. The key assumptions applied in the determination of the value in use including a sensitivity analysis, are disclosed and further explained in Note 11 to the financial statements.

The carrying amount of the intangible assets as at 31 December 2015 is US$33.2 million (2014: US$91.5 million).

(b) Impairment of loans and receivables

The Group assesses at the end of each reporting period whether there is any objective evidence that a financial asset is impaired. Factors such as the probability of insolvency or significant financial difficulties of the debtor and default or significant delay in payments are objective evidence of impairment. In determining whether there is objective evidence of impairment, the Group considers whether there is observable data indicating that there have been significant changes in the debtor's payment ability or whether there have been significant changes with adverse effect in the technological, market, economic or legal environment in which the debtor operates in.

Where there is objective evidence of impairment, the amount and timing of future cash flows are estimated based on historical loss experience for assets with similar credit risk characteristics. The carrying amount of the Group's loans and receivables at the end of the reporting period is disclosed in Note 14 to the financial statements.

4 | BUSINESS COMBINATIONS

Acquisition in 2015

KrisEnergy (Block A Aceh) B.V. ["KEBAABV"]

On 12 January 2015, the Group completed its acquisition of a 100% equity interest in KrisEnergy (Block A Aceh) B.V. (formerly known as Premier Oil Sumatra (North) B.V.) which holds 41.6666% working interest in the Block A Aceh Production Sharing Contract ("PSC") from Premier Oil Overseas B.V., for a consideration of US$50.5 million. The Group has acquired KEBAABV to expand its development portfolio which is key to near-term growth in reserves and production.

The fair value of the identifiable assets and liabilities of KEBAABV as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets	
Exploration and evaluation assets	79,668,776
Investment securities	216,000
Trade and other receivables	5,501,025
Prepayments	10,048
Inventories	10,136,647
	95,532,496
Liabilities	
Trade and other payables	23,051,025
Accrued operating expenses	174,473
Tax payables	118,474
Provisions	1,280,662
	24,624,634
Total identifiable net assets at fair value	**70,907,862**
Intra-group settlement	22,542,085
Excess of fair value of net assets acquired over consideration paid	(42,993,442)
Net cash outflow on acquisition	**50,456,505**

The carrying value of the trade and other receivables amounting to US$5.5 million was an approximate of its fair value. None of the trade and other receivables has been impaired and it is expected that full contractual amounts can be collected.

Included in trade and other payables is KEBAABV intra-group payables of US$22.5 million, which is included as part of the cash consideration paid to Premier Oil Overseas B.V.

The excess of fair value of net assets acquired over consideration paid of US$43.0 million comprises the probable reserves arising from the exploration and evaluation assets acquired.

From the date of acquisition to 31 December 2015, KEBAABV did not contribute to the Group revenue and contributed US$0.4 million of net profit to the Group. If the business combination had taken place at the beginning of the year, there would be no impact to the Group's revenue and the loss for the year.

Acquisition in 2014

KrisEnergy G10 (Thailand) Ltd. ["KEG10"]

On 27 May 2014, the Group completed its acquisition of a 100% equity interest in KrisEnergy G10 (Thailand) Ltd. (formerly known as MP G10 (Thailand) Limited) which holds a 75.0% working interest in, and operatorship of, the G10/48 licence in the Gulf of Thailand from Mubadala Petroleum, for a consideration of US$106.5 million. The Group has acquired KEG10 to expand its development portfolio which is key to near-term growth in reserves and production.

The fair value of the identifiable assets and liabilities of KEG10 as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets	
Exploration and evaluation assets	56,238,116
Inventories	138,129
Trade and other receivables	280,739
Cash and bank balances	4,848,569
	61,505,553
Liabilities	
Trade and other payables	89,877,629
Total identifiable net liabilities at fair value	**(28,372,076)**
Intra-group settlement	88,598,387
Goodwill	46,261,884
Consideration settled in cash	**106,488,195**
Less: cash and bank balances	(4,848,569)
Net cash outflow on acquisition	**101,639,626**

The carrying value of the trade and other receivables amounting to US$0.3 million was an approximate of its fair value. None of the trade and other receivables has been impaired and it was expected that the full contractual amounts can be collected.

Included in trade and other payables is KEG10 intra-group debts of US$88.6 million, which is included as part of the cash consideration paid to Mubadala Petroleum.

The goodwill of US$46.3 million comprises the value of strengthening the Group's portfolio for development assets held in the region. None of the goodwill is expected to be deductible for tax purposes.

From the date of acquisition to 31 December 2015, KEG10 did not contribute to the Group revenue and contributed US$0.3 million of net loss to the Group. If the business combination had taken place at the beginning of the year, there would be no impact to the Group's revenue but the loss for the year would have been US$50.4 million.

KrisEnergy (Apsara) Ltd. ["KEAPL"]

On 1 October 2014, the Group completed its acquisition of the entire share capital of KrisEnergy (Apsara) Ltd. (formerly known as Chevron Overseas Petroleum (Cambodia) Limited), which holds a 30% working interest in, and operatorship of, Cambodia Block A, for a consideration of US$65.6 million. The Group has acquired KEAPL to gain operatorship of Cambodia Block A and to steer the Apsara development plans forward to first production as quickly and cost effectively as possible.

The fair value of the identifiable assets and liabilities of KEAPL as at date of acquisition was:

	FAIR VALUE RECOGNISED ON ACQUISITION
BALANCE SHEET	US$
Assets	
Exploration and evaluation assets	63,725,851
Trade and other receivables	652,138
	64,377,989
Liabilities	
Trade and other payables	101,462
Total identifiable net assets at fair value	**64,276,527**
Goodwill	1,300,286
Consideration settled in cash	**65,576,813**

The carrying value of the trade and other receivables amounting to US$0.7 million was an approximate of its fair value. None of the trade and other receivables has been impaired and it was expected that the full contractual amounts can be collected.

The goodwill of US$1.3 million comprises the value of strengthening the Group's portfolio for development assets held in the region. None of the goodwill is expected to be deductible for tax purposes.

From the date of acquisition to 31 December 2015, KEAPL did not contribute to the Group revenue and contributed US$0.1 million of net loss to the Group. If the business combination had taken place at the beginning of the year, there would be no impact to the Group's revenue but the loss for the year would have been US$50.4 million.

5 | INTERESTS IN OIL & GAS BLOCKS

The Group holds interests in each contract area for the right to explore and produce oil and gas properties. 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 OPERATON	% OF EFFECTIVE WORKING INTEREST	
				2015	2014
G10/48 Concession (7 December 2035)	KrisEnergy (Gulf of Thailand) Ltd. (25.0%), KrisEnergy G10 (Thailand) Ltd. (64.0%) and Wassana G10 Ltd (11.0%)	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	100.00	100.00
G11/48 Concession (12 February 2036)	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	22.50	22.50
Cambodia Block A PA (No expiry date for exploration stage)	KrisEnergy (Cambodia) Ltd (25.0%) and KrisEnergy (Apsara) Ltd. (30.0%)	Drilling of exploration wells under the Petroleum Agreement ("PA") with General Department of Petroleum (formerly known as Cambodian National Petroleum Authority)	Offshore Cambodia	55.00	55.00
Glagah-Kambuna TAC (16 December 2016)	KrisEnergy Glagah-Kambuna B.V.	Exploration and production of petroleum under Technical Assistance Contract ("TAC") with Indonesia Governmental Authority	Indonesia	25.00	25.00
Kutai PSC (15 January 2037)	KrisEnergy Kutai B.V. (24.6%) and KrisEnergy Kutei B.V. (30.0%)	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	54.60	54.60
B8/32 Concession (31 July 2020)	KrisEnergy (Gulf of Thailand) Ltd. / Orange Energy Ltd. / B8/32 Partners Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	4.63	4.63
B9A Concession (16 July 2041)	KrisEnergy (Gulf of Thailand) Ltd./ Orange Energy Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	4.63	4.63
Block 105 PSC (2 February 2040)[1, 2]	KrisEnergy (Song Hong 105) Ltd	Exploration and development of petroleum under Production Sharing Contract with Vietnam Government Authority	Offshore Vietnam	51.00	33.33
Block 120 PSC (22 January 2039)[1]	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)	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)	KrisEnergy (East Muriah) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	50.00	50.00
Tanjung Aru PSC (18 December 2041)[3]	KrisEnergy (Bala-Balakang) B.V. (formerly known as KrisEnergy (Tanjung Aru) 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)	KrisEnergy (Gulf of Thailand) Ltd.	Exploration and production of petroleum under Concession Agreement with Department of Mineral Resources	Gulf of Thailand	30.00	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

CONTRACT AREA (DATE OF EXPIRY)	HELD BY	DESCRIPTION	PLACE OF OPERATON	% OF EFFECTIVE WORKING INTEREST	
				2015	2014
Block 115/09 (30 March 2044)	KrisEnergy (Asia) 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 2019)	KrisEnergy (Asia) Ltd.	Exploration and development of petroleum under Production Sharing Contract with Bangladesh Governmental Authority	Bangladesh	45.00	45.00
Block A Aceh PSC[4] (31 August 2031)	KrisEnergy (Block A Aceh) B.V.	Exploration and production of petroleum under Production Sharing Contract with Indonesia Governmental Authority	Indonesia	41.67	41.67

Notes

1 Pursuant to the deed executed in relation to the default and subsequent withdrawal of Neon Energy (Song Hong) Pty Ltd. ("Neon Energy") from Block 105 PSC and Block 120 PSC, Neon Energy's working interest is proportionately transferred to Eni Vietnam B.V. ("ENI"), KrisEnergy (Song Hong 105) Ltd and KrisEnergy (Phu Khanh 120) Ltd. On 13 February 2015, the approvals for the revised working interest have been received from the Ministry of Industry and Trade of Vietnam.

2 Pursuant to the deed executed in relation to the withdrawal of ENI from Block 105 PSC, the operatorship and 66.67% working interest is transferred to KrisEnergy (Song Hong 105) Ltd. On 28 September 2015, the Ministry of Industry and Trade of Vietnam approved the transfer of ENI's working interest to KrisEnergy (Song Hong 105) Ltd., and the concurrent transfer of 49.0% working interest in Block 105 PSC to Vietnam Oil and Gas Group.

3 Pursuant to the deed executed in relation to the default and subsequent withdrawal of Neon Energy from Tanjung Aru PSC, Neon Energy's working interest is transferred to KrisEnergy (Tanjung Aru) B.V. On 5 August 2015, the approval for the transfer of working interest have been received from Special Task Force for Upstream Oil and Gas Business Activities ("SKKMigas") and The Ministry of Energy and Mineral Resources of Republic of Indonesia.

4 On 1 July 2014, KrisEnergy Asia Holdings B.V. acquired 41.67% working interest in the Block A Aceh PSC. On 12 January 2015, approval for the change of control has been received from the Government of Indonesia and the provincial government of Aceh.

6 | LOSS BEFORE TAX

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

GROUP

	NOTE	2015	2014
		US$	US$
Revenue:			
Sale of crude oil		40,680,319	49,792,944
Sale of gas		19,490,880	25,112,285
		60,171,199	**74,905,229**
Cost of sales:			
Depletion and amortisation of oil and gas properties		(42,389,272)	(28,714,703)
Exploration and operating costs		(30,518,596)	(19,192,177)
Thai Petroleum royalties and remuneration paid		(4,928,949)	(7,329,327)
Inventories written down	13	(17,657,739)	–
		(95,494,556)	**(55,236,207)**
Other income is mainly made up of the following items:			
Excess of fair value of net assets acquired over consideration paid	4	42,993,442	–
Gain on disposal of assets	16	24,558,714	–
Gain on transfer of working interests		34,100,337	–
Joint operator overhead charges		3,353,547	1,248,246
Income from transfer of joint study arrangement		–	1,038,279
Income from shared facilities in joint operations		601,197	808,486
Income from technical services provided to joint operations		4,870,677	3,695,855
Value added tax recovered		–	1,747,694

GROUP

	NOTE	2015 US$	2014 US$
General and administrative expenses is mainly made up of the following items:			
Consultants' fees		(989,135)	(770,916)
Data purchase and subscriptions		(528,703)	(810,133)
Database rental		(703,483)	(1,351,419)
Depreciation of other plant and equipment	10	(807,727)	(426,676)
Employee benefits expense			
– Salaries and bonuses		(11,809,339)	(15,460,439)
– Share-based payments	22	(2,516,377)	(3,122,919)
– Central Provident Fund contributions		(284,488)	(274,696)
– Employee defined benefit		(164,333)	(226,224)
– Other short-term benefits		(647,351)	(709,924)
Operating lease expense		(786,754)	(794,194)
Professional fees		(5,274,414)	(6,012,737)
Travel and entertainment		(1,216,258)	(1,780,528)
Other operating expenses is mainly made up of the following items:			
Impairment loss on exploration and evaluation assets	8	(584,309)	–
Impairment loss on oil and gas properties	9	(11,116,545)	–
Impairment loss on intangible assets	11	(58,177,765)	–
Joint study expenses		(144,455)	(703,902)
Net fair value loss on embedded derivatives		–	(6,137,226)
Net fair value gain/(loss) on financial instruments		2,151,703	(2,960,446)
Finance costs:			
Financing fees		(1,561,980)	(6,849,814)
Interest on bank borrowings		(2,600,027)	(591,733)
Interest and redemption premium on callable bonds		–	(8,193,618)
Interest on Multi-currency Medium Term Notes		(14,376,838)	(6,875,962)
Unwinding of discount on decommissioning provisions	20	(919,239)	(642,073)
		(19,458,084)	**(23,153,200)**

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% to 15% 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% 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% of petroleum profit.

Loss per share

Basic loss per Share is 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 is 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 22).

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

	2015 US$	2014 US$
Loss for the year attributable to owners of the Company used in the computation of basic and diluted loss per share	(41,675,825)	(50,370,496)
	NO. OF SHARES	NO. OF SHARES
Weighted average number of ordinary Shares for basic loss per share computation	1,221,330,651	1,046,967,214
Effects of dilution		
– Vesting of performance Shares	10,080,846	5,517,748
Weighted average number of ordinary Shares for diluted loss per share computation	**1,231,411,497**	**1,052,484,962**

7 | TAXATION

The major components of tax expense for the years ended 31 December 2015 and 2014 are:

GROUP

	2015 US$	2014 US$
Current tax:		
– Current tax charge	2,629,286	12,782,388
– Under/(over) provision in respect of previous years	12,108	(90,717)
	2,641,394	**12,691,671**
Deferred tax:		
– Origination/(reversal) of temporary differences	650,297	(1,600,045)
Tax expense recognised in profit or loss	**3,291,691**	**11,091,626**

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 2015 and 2014 is as follows:

GROUP

	2015 US$	2014 US$
Loss before tax	(45,282,143)	(39,278,870)
Tax at domestic rates applicable in the countries where the Group operates	(1,047,243)	5,250,245
Adjustments:		
Non-deductible expenses	3,174,673	738,974
Income not subject to tax	(12,031,502)	–
Deferred tax assets not recognised	13,183,655	5,216,307
Effect of partial tax exemption and tax relief	–	(19,932)
Under/(over) provision in respect of previous years	12,108	(90,717)
Others	–	(3,251)
Tax expense recognised in profit or loss	**3,291,691**	**11,091,626**

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

The nature of expenses that are not deductible for tax purposes are mainly made up of the following items:

GROUP

	2015 US$	2014 US$
Unrealised foreign exchange loss	443,856	325,607

Deferred tax

Deferred tax at 31 December relates to the following:

GROUP	CONSOLIDATED STATEMENT OF FINANCIAL POSITION		CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME	
	2015 US$	2014 US$	2015 US$	2014 US$
Deferred tax liabilities				
Fair value adjustment on acquired reserves	40,959,937	41,339,217	(379,280)	(1,321,202)
Deferred tax assets				
Provisions	–	(1,029,577)	1,029,577	(278,843)
Deferred tax expense/(benefit)			**650,297**	**(1,600,045)**
Net deferred tax liabilities	**40,959,937**	**40,309,640**		

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.

GROUP

	2015	2014
	US$	US$
Differences in depreciation, depletion and amortisation for tax purposes	51,895,644	48,581,470
Unutilised tax losses	48,979,645	39,110,165
	100,875,289	**87,691,635**

The Group offsets tax assets and liabilities 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.

8 | EXPLORATION & EVALUATION ASSETS

GROUP

	NOTE	US$
Cost		
At 1 January 2014		200,261,113
Additions		82,553,592
Acquisition of subsidiaries	4	119,963,967
At 31 December 2014 and 1 January 2015		**402,778,672**
Additions		104,342,738
Acquisition of subsidiary	4	79,668,776
Transfer to oil and gas properties	9	(138,800,870)
As at 31 December 2015		**447,989,316**
Accumulated impairment		
At 1 January 2014, 31 December 2014 and 1 January 2015		–
Impairment loss		584,309
As at 31 December 2015		**584,309**
Net book value		
As at 31 December 2015		**447,405,007**
As at 31 December 2014		**402,778,672**

9 | OIL & GAS PROPERTIES

GROUP

	NOTE	US$
Cost		
At 1 January 2014		297,493,592
Additions		24,453,401
At 31 December 2014 and 1 January 2015		**321,946,993**
Additions		193,346,053
Transfer from exploration and evaluation assets	8	138,800,870
As at 31 December 2015		**654,093,916**
Accumulated depletion, amortisation and impairment		
At 1 January 2014		156,897,511
Charge for the year		28,714,703
At 31 December 2014 and 1 January 2015		**185,612,214**
Charge for the year		42,297,104
Impairment loss		11,116,545
As at 31 December 2015		**239,025,863**
Net book value		
As at 31 December 2015		**415,068,053**
As at 31 December 2014		**136,334,779**

10 | OTHER PROPERTY, PLANT & EQUIPMENT

GROUP	RENOVATION	FURNITURE AND FITTINGS	OFFICE EQUIPMENT	COMPUTERS	REFURBISHMENT ASSETS	TOTAL
	US$	US$	US$	US$		US$
Cost						
At 1 January 2014	945,320	104,558	44,790	986,451	–	2,081,119
Additions	696,852	107,315	122,905	344,630	–	1,271,702
Disposals	(92,390)	(46,098)	(10,275)	(32,647)	–	(181,410)
Exchange differences	(34,897)	(545)	(151)	(29,223)	–	(64,816)
At 31 December 2014 and 1 January 2015	**1,514,885**	**165,230**	**157,269**	**1,269,211**	**–**	**3,106,595**
Additions	118,707	54,073	162,638	242,258	10,323,937	10,901,613
Disposals	(1,267)	–	–	–	–	(1,267)
Exchange differences	(91,095)	(5,477)	(1,260)	(74,375)	–	(172,207)
At 31 December 2015	**1,541,230**	**213,826**	**318,647**	**1,437,094**	**10,323,937**	**13,834,734**
Accumulated depreciation						
At 1 January 2014	834,706	76,801	31,608	805,779	–	1,748,894
Charge for the year	148,495	33,482	20,210	224,489	–	426,676
Disposals	(81,775)	(39,553)	(9,487)	(30,601)	–	(161,416)
Exchange differences	(35,123)	(1,212)	(580)	(31,847)	–	(68,762)
At 31 December 2014 and 1 January 2015	**866,303**	**69,518**	**41,751**	**967,820**	**–**	**1,945,392**
Charge for the year	399,221	52,765	74,999	280,742	–	807,727
Disposals	(127)	–	–	–	–	(127)
Exchange differences	(66,219)	(2,790)	(1,236)	(67,633)	–	(137,878)
At 31 December 2015	**1,199,178**	**119,493**	**115,514**	**1,180,929**	**–**	**2,615,114**
Net carrying amount						
At 31 December 2015	**342,052**	**94,333**	**203,133**	**256,165**	**10,323,937**	**11,219,620**
At 31 December 2014	**648,582**	**95,712**	**115,518**	**301,391**	**–**	**1,161,203**

11 | INTANGIBLE ASSETS

GROUP	GOODWILL	OTHERS	TOTAL
	US$	US$	US$
Cost			
At 1 January 2014	58,477,823	1,669,721	60,147,544
Acquisition of subsidiaries	47,562,170	–	47,562,170
At 31 December 2014, 1 January 2015 and 31 December 2015	**106,039,993**	**1,669,721**	**107,709,714**
Accumulated amortisation and impairment loss			
At 1 January 2014, 31 December 2014 and 1 January 2015	16,256,809	–	16,256,809
Charge for the year	–	92,168	92,168
Impairment loss	57,600,330	577,435	58,177,765
At 31 December 2015	**73,857,139**	**669,603**	**74,526,742**
Net carrying amount			
At 31 December 2015	**32,182,854**	**1,000,118**	**33,182,972**
At 31 December 2014	**89,783,184**	**1,669,721**	**91,452,905**

Goodwill

Goodwill arises principally because of the following factors:

(a) The going concern value implicit in our ability to sustain and/or grow our business by increasing reserves and resources through new discoveries

(b) The ability to capture unique synergies that can be realised from managing a portfolio of both acquired and existing assets

(c) The requirement to recognise deferred tax assets and liabilities for the difference between the assigned values and the tax bases of assets acquired and liabilities assumed in a business combination at amounts that do not reflect fair value.

Other intangible assets

GROUP

	2015	2014
	US$	US$
0.75% overriding royalty interest in G10/48 and G11/48 Concessions	636,146	1,300,000
Leasehold bonus for G10/48 Concession	263,972	269,721
Block 105 PSC	100,000	100,000
	1,000,118	**1,669,721**

The Group was assigned the overriding royalty interest from the acquisitions of KrisEnergy Oil and Gas (Thailand) Ltd ("KEOG") and KrisEnergy Resources (Thailand) Ltd ("KER"). The overriding royalty interest entitles the Group rights to the revenues derived from the production and disposal of all of the oil, gas, and other minerals, in, on, under, and that may be produced and saved from G10/48 and G11/48 Concessions.

Impairment testing

For the purposes of assessing for any impairment, goodwill and other intangible assets acquired through business combinations have been allocated as follows:

	GOODWILL		OTHERS	
	2015	2014	2015	2014
	US$	US$	US$	US$
G10/48 Concession	23,727,962	57,149,300	900,118	919,721
G11/48 Concession	–	10,887,416	–	650,000
B9A and B8/32 Concessions	–	13,301,576	–	–
Bulu PSC	7,144,606	7,144,606	–	–
Block 105 PSC	–	–	100,000	100,000
Cambodia Block A PA	1,300,286	1,300,286	–	–
	32,182,854	**89,783,184**	**1,000,118**	**1,669,721**

As at 31 December 2015, an impairment loss of US$69.9 million was 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.

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

- Production volumes;
- Discount rates; and
- 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. It is estimated that, if all production were to be reduced by 2% for the whole term of the contract area, this would not be sufficient to reduce the excess of the recoverable amount over the carrying amounts of the individual CGUs to zero.

Consequently, management believes no reasonably possible change in the production assumptions would cause the carrying amount of goodwill and/or other non-current assets to exceed their recoverable amount. For the CGUs which are written down to its recoverable amount during the year, a further reduction in the production would result in further impairment.

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% to 10% (2014: 8% to 10%) 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, 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$50 to US$90 (2014: US$60 to US$90) per barrel.

12 | INVESTMENT IN SUBSIDIARIES

COMPANY

	NOTE	2015	2014
		US$	US$
Unquoted Shares, at cost		326,809,783	326,759,705
Capital contribution for share-based payments	22	6,488,665	3,797,501
		333,298,448	**330,557,206**

The Group has the following investment in subsidiaries:

NAME OF ENTITIES	PRINCIPAL ACTIVITIES	PRINCIPAL PLACE OF BUSINESS	COUNTRY OF INCORPORATION	% OF EQUITY INTEREST	
				2015	2014
KrisEnergy Holding Company Ltd[3]	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy Pte. Ltd.	Provision of management support service	Singapore	Singapore	100	100
KrisEnergy (Management Services) Ltd	Provision of offshore management support service	Singapore	British Virgin Islands	100	100
KrisEnergy (Asia) Ltd.	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy International (Thailand) Holdings Ltd[3]	Investment holding	Thailand	British Virgin Islands	100	100
KrisEnergy (Gulf of Thailand) Ltd.[3]	Investment holding	Thailand	Cayman Islands	100	100
KrisEnergy Oil and Gas (Thailand) Ltd	Exploration and production of oil and gas	Thailand	Thailand	100	100
KrisEnergy Resources (Thailand) Ltd	Exploration and production of oil and gas	Thailand	Thailand	100	100
KrisEnergy Management Ltd	Investment holding	Singapore	British Virgin Islands	85.33	100
KrisEnergy (Cambodia) Holding Ltd	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy (Cambodia) Ltd	Exploration and production of oil and gas	Cambodia	Cambodia	100	100
KrisEnergy (Phu Khanh 120) Ltd	Exploration and production of oil and gas	Vietnam	British Virgin Islands	100	100
KrisEnergy (Song Hong 105) Ltd	Exploration and production of oil and gas	Vietnam	British Virgin Islands	100	100
KrisEnergy (Vietnam 115) Ltd	Dormant	Singapore	British Virgin Islands	100	100
KrisEnergy Asia Coöperatief U.A.[3]	Investment holding	Singapore	The Netherlands	100	100
KrisEnergy Asia Holdings B.V.[3]	Investment holding	Singapore	The Netherlands	100	100
KrisEnergy Glagah-Kambuna B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Marine B.V. (formerly known as KrisEnergy (Bangora) B.V.)[1]	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Kutai B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Andaman II) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Marine Pte. Ltd.	Investment holding	Singapore	Singapore	100	100
KrisEnergy Kutei B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy East Seruway B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Bangladesh SS-11) Ltd	Investment holding	Singapore	British Virgin Islands	100	100
SJ Production Barge Ltd	Exploration and production of oil and gas	Singapore	British Virgin Islands	100	100
B Block Limited	Investment holding	Singapore	British Virgin Islands	100	100
KrisEnergy (Satria) Ltd	Exploration and production of oil and gas	Indonesia	British Virgin Islands	100	100
KrisEnergy (East Muriah) Limited	Exploration and production of oil and gas	Indonesia	British Virgin Islands	100	100
KrisEnergy (Ampuh) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Andaman Timur) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Nemo) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Sakti) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Bala-Balakang) B.V. (formerly known as KrisEnergy (Tanjung Aru) B.V.)[2]	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy (Udan Emas) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
KrisEnergy Bangladesh Limited[3]	Exploration and production of oil and gas	Bangladesh	Jersey	100	100
KrisEnergy (Apsara) Ltd.	Exploration and production of oil and gas	Cambodia	Bermuda	100	100
KrisEnergy G10 (Thailand) Ltd.	Exploration and production of oil and gas	Thailand	Thailand	100	100
KrisEnergy (Block A Aceh) B.V.	Exploration and production of oil and gas	Indonesia	The Netherlands	100	100
Wassana G10 Ltd	Exploration and production of oil and gas	Thailand	British Virgin Islands	100	–
KrisEnergy Netherlands Holdings Pte Ltd	Investment holding	Singapore	Singapore	100	–

Notes

1 With effect from 12 May 2015, the name of the Company was changed from KrisEnergy (Bangora) B.V. to KrisEnergy Marine B.V.

2 With effect from 13 October 2015, the name of the Company was changed from KrisEnergy (Tanjung Aru) B.V. to KrisEnergy (Bala-Balakang) B.V.

3 Capital stock in this entity pledged as collateral for KEAL Revolving Credit Facility (Note 19)

13 | INVENTORIES

GROUP

	2015 US$	2014 US$
Balance sheet		
Drilling supplies and materials	20,610,481	12,839,947
Crude oil	7,661,906	1,830,127
	28,272,387	**14,670,074**
Profit or loss		
Inventories recognised as an expense in cost of sales	32,514,624	126,170
Inclusive of the following charge		
Inventories written down	17,657,739	–

14 | TRADE & OTHER RECEIVABLES

	NOTE	GROUP 2015 US$	GROUP 2014 US$	COMPANY 2015 US$	COMPANY 2014 US$
Trade and other receivables (current)					
Trade receivables		8,263,725	7,380,102	–	–
Refundable deposits		447,578	498,761	–	–
Other receivables		42,348,021	36,363,553	–	–
Joint operation receivables		15,166,945	20,923,075	–	–
		66,226,269	**65,165,491**	**–**	**–**
Other receivables (non-current)					
Amount due from subsidiaries		–	–	884,507,158	645,464,973
Total trade and other receivables (current and non-current)		**66,226,269**	**65,165,491**	**884,507,158**	**645,464,973**
Add: cash and bank balances	15	29,351,634	51,334,088	433,269	1,610,557
Less: advances for acquisition		–	(4,152,697)	–	–
Total loans and receivables		**95,577,903**	**112,346,882**	**884,940,427**	**647,075,530**

Other receivables

	GROUP 2015 US$	GROUP 2014 US$	COMPANY 2015 US$	COMPANY 2014 US$
Advances for acquisition	–	4,152,697	–	–
Payment on behalf of joint operation's partners	9,023,053	7,862,571	–	–
Proportionate share of joint operation's other receivables	2,783,038	11,550,095	–	–
Value added tax receivables	30,357,422	12,635,031	–	–
Others	184,508	163,159	–	–
	42,348,021	**36,363,553**	**–**	**–**

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.

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.

Amount due from subsidiaries are non-trade related, unsecured, non-interest bearing, and repayable upon demand.

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

GROUP

	2015	2014
	US$	US$
Thai Baht	3,105,667	721,596

At the reporting date, the Group does not have any receivables that are past due or impaired, or would otherwise be past due but not impaired.

15 | CASH & BANK BALANCES

	GROUP		COMPANY	
	2015	2014	2015	2014
	US$	US$	US$	US$
Cash at banks and on hand	27,851,634	47,575,264	433,269	1,610,557
Cash collateralised	1,500,000	3,758,824	–	–
Cash and bank balances	**29,351,634**	**51,334,088**	**433,269**	**1,610,557**

Cash at banks earns interest at floating rates based on daily bank deposit rates. Included in cash and bank balances is cash collateralised to a bank of US$1.5 million (2014: US$3.8 million) under the KEHCL Revolving Credit Facility. The KEHCL Revolving Credit Facility was terminated in 2014, US$2.3 million was released in 2015 and US$1.5 million will be released in 2017.

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

GROUP

	2015	2014
	US$	US$
Cash and bank balances	29,351,634	51,334,088
Less: restricted cash	(1,500,000)	(3,758,824)
Cash and bank equivalents	**27,851,634**	**47,575,264**

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

GROUP

	2015	2014
	US$	US$
Thai Baht	55,166	123,826
Euro Dollar	42,468	127,102
Singapore Dollar	27,780	250,789
United States Dollar	937,776	356,656

16 | ASSETS HELD FOR SALE

On 23 December 2014, the Group entered into a sale and purchase agreement to dispose of the mobile production package, which includes the mobile offshore production unit ("MOPU"), the catenary anchor leg mooring buoy ("CALM Buoy") and the two hoses that connect from the MOPU to the CALM Buoy ("Manuli Hoses"). As at 31 December 2014, the carrying amount of the assets related to the mobile production package has been presented in the consolidated statement of financial position as "Assets held for sale". The disposal was completed on 17 June 2015 with a gain on disposal of assets of US$24.6 million recognised (Note 6).

17 | SHARE CAPITAL & RESERVE

GROUP AND COMPANY

SHARE CAPITAL	2015		2014	
	NO. OF SHARES	US$	NO. OF SHARES	US$
Issued and fully paid ordinary Shares				
At 1 January	1,047,963,898	1,309,955	1,046,154,000	1,307,693
Vesting of equity-settled share transactions with employees on 21 July 2014	–	–	1,809,898	2,262
Vesting of equity-settled share transactions with employees on 20 July 2015	2,025,674	2,532	–	–
Rights issue on 11 August 2015 for cash	440,144,838	550,181	–	–
Vesting of equity-settled share transactions with employees on 31 December 2015	3,916,835	4,896	–	–
At 31 December	**1,494,051,245**	**1,867,564**	**1,047,963,898**	**1,309,955**

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 (2014: US$0.00125) each.

GROUP AND COMPANY

SHARE PREMIUM	2015	2014
	US$	US$
At 1 January	604,582,768	602,938,278
Vesting of equity-settled share transactions with employees on 21 July 2014	–	1,644,490
Vesting of equity-settled share transactions with employees on 20 July 2015	1,606,818	–
Rights issue on 11 August 2015 for cash	123,785,875	–
Share issuance expense	(3,660,530)	–
Vesting of equity-settled share transactions with employees on 31 December 2015	930,108	–
At 31 December	**727,245,039**	**604,582,768**

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.

18 TRADE & OTHER PAYABLES

	NOTE	GROUP 2015 US$	GROUP 2014 US$	COMPANY 2015 US$	COMPANY 2014 US$
Trade and other payables (current)					
Trade payables		23,739,493	5,769,552	27,073	–
Joint operation payables		–	315,926	–	–
Staff payroll and bonus payables		258,137	4,429,846	–	–
Other payables		7,914,229	16,877,701	3,322,277	3,770,137
		31,911,859	**27,393,025**	**3,349,350**	**3,770,137**
Other payables (non-current)					
Amounts due to subsidiaries		–	–	239,785,877	119,062,800
Other payables		34,843,307	–	–	–
Total trade and other payables (current and non-current)		**66,755,166**	**27,393,025**	**243,135,227**	**122,832,937**
Accrued operating expenses		38,015,365	20,191,470	782,472	275,728
Loans and borrowings	19	304,571,912	257,440,512	229,571,912	247,440,512
Employee benefit liability	21	1,888,841	1,483,647	–	–
Total financial liabilities carried at amortised cost		**411,231,284**	**306,508,654**	**473,489,611**	**370,549,177**

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

	GROUP 2015 US$	GROUP 2014 US$	COMPANY 2015 US$	COMPANY 2014 US$
Proportionate share of joint operations' other payables	1,405,611	2,033,596	–	–
Accrued interest payable for Multi-currency Medium Term Note	3,322,277	3,744,039	3,322,277	3,744,039
Deposit on asset held for sale	–	11,000,000	–	–
Value added tax payables	3,044,972	244,260	–	–
Others	141,369	(144,194)	–	26,098
	7,914,229	**16,877,701**	**3,322,277**	**3,770,137**

Included in accrued operating expenses is the Group's proportionate share of joint operations' accrued expenses amounting to US$32.2 million (2014: US$15.0 million).

Amount due to subsidiaries are unsecured, non-interest bearing and repayable on demand.

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

GROUP

	2015 US$	2014 US$
Thai Baht	3,220,460	694,458

19 | LOANS & BORROWINGS

		GROUP		COMPANY	
	MATURITY	2015	2014	2015	2014
		US$	US$	US$	US$
Non-current					
Revolving credit facility	2017	75,000,000	10,000,000	–	–
Multi-currency Medium Term Notes	2017/2018	229,571,912	247,440,512	229,571,912	247,440,512
		304,571,912	**257,440,512**	**229,571,912**	**247,440,512**

Multi-currency Medium Term Note

On 26 May 2014, the Company established a S$500.0 million Multi-currency Medium Term Note Program ("MTN Program") with The Hongkong and Shanghai Banking Corporation Limited and Standard Chartered Bank. Under the MTN Program, the Company issued a S$130.0 million three-year fixed rate bond on 9 June 2014 (the "2017 Notes"), with a coupon of 6.25%. On 22 August 2014, the Company issued a S$200.0 million four-year fixed rate bond with a coupon of 5.75% (the "2018 Notes").

KEAL Revolving Credit Facility

On 24 March 2014, KrisEnergy (Asia) Ltd ("Borrower"), a wholly owned subsidiary of the Company, entered into a facility agreement with The Hongkong and Shanghai Banking Corporation for a US$100.0 million revolving credit facility ("KEAL Revolving Credit Facility") for a period of two years with an option to extend to three years.

As at 31 December 2015, the Borrower has drawn down US$75.0 million (2014: US$10.0 million) and issued bank guarantees of US$10.4 million (2014: US$9.3 million) from the KEAL Revolving Credit Facility. The interest rate of the facility is at LIBOR plus 2.95% per annum and has no fixed repayment term.

The Parent Guarantors of the KEAL Revolving Credit Facility are the Company and KrisEnergy Holding Company Ltd. The Subsidiary Guarantors are KrisEnergy International (Thailand) Holdings Ltd, KrisEnergy Asia Coöperatief U.A., KrisEnergy Asia Holdings B.V., KrisEnergy (Gulf of Thailand) Ltd. and KrisEnergy Bangladesh Limited.

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

20 PROVISIONS

GROUP

	US$
Decommissioning provisions	
At 1 January 2014	23,741,232
Arising during the year	14,218,838
Unwinding of discount	642,073
At 31 December 2014 and 1 January 2015	**38,602,143**
Arising during the year	8,951,487
Unwinding of discount	919,239
At 31 December 2015	**48,472,869**

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 decommissioning provision represents the present value of decommissioning costs relating to oil and gas properties, which are expected to be incurred up to 2021 which is when the producing oil and gas properties are expected to cease operations. These provisions have been created based on the Group's internal estimates. Assumptions based on the current economic environment have been made, which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required that will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

The average discount rate used in the calculation of the provisions as at 31 December 2015 is 7.8% (2014: 2.6%)

21 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 basic 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

	2015	2014
	US$	US$
Present value of defined benefit obligations	2,191,985	1,344,508
Re-measurement of defined benefit obligations	(303,144)	139,139
Net liability arising from defined benefit obligations	**1,888,841**	**1,483,647**

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

GROUP

	US$
At 1 January 2014	884,691
Interest cost	71,662
Current service cost	432,430
Past service cost	39,858
Re-measurement (gains)/losses	
Actuarial gains and losses arising from changes in demographic assumption	(502)
Actuarial gains and losses arising from changes in financial assumption	100,823
Actuarial gains and losses arising from experience adjustments	38,818
Benefits paid	(84,133)
At 31 December 2014 and 1 January 2015	**1,483,647**
Interest cost	80,135
Current service cost	731,640
Past service cost	(20,818)
Re-measurement (gains)/losses	
Re-measurement of other long term employee benefits	(2,252)
Actuarial gains and losses arising from changes in demographic assumption	56
Actuarial gains and losses arising from changes in financial assumption	(226,880)
Actuarial gains and losses arising from experience adjustments	(76,320)
Benefits paid	(80,367)
At 31 December 2015	**1,888,841**

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:

	2015	2014
Retirement age	55 – 70 years	55 – 65 years
Discount rate	3% - 9% per annum	3% - 8% per annum
Long-term salary increase	3% - 5% per annum	5% - 8% per annum
Voluntary resignation	6% for employee before the age of 30 and linear decrease until 0% at the age of 56	6% for employee before the age of 30 and linear decrease until 0% at the age of 55

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:

		2015	2014
		US$	US$
Discount rate	+ 50 basis points	(27,070)	(45,272)
	- 50 basis points	30,380	50,880

22 SHARE-BASED PAYMENTS

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

GROUP

	2015	2014
	US$	US$
Expense arising from cash-settled share-based payment transactions	(15,412)	314,573
Expense arising from equity-settled share-based payment transactions	2,531,789	2,808,346
	2,516,377	**3,122,919**

Virtual Shares Award ("VSA")

On 18 September 2013, the Company awarded 783,764 virtual Shares to its employees under the VSA scheme. 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 1 July 2014 and 24 November 2014, the Company awarded additional 430,874 and 400,770 virtual Shares respectively to its employees. On 21 July 2014, 398,881 virtual Shares vested at vesting share price of S$0.775.

On 9 November 2015, the Company awarded additional 3,308,215 virtual Shares to its employees. On 20 July 2015 and 31 December 2015, 486,572 and 1,102,743 virtual Shares vested at vesting share price of S$0.400 and S$0.166 respectively.

The carrying amount to the liability relating to the VSA as at 31 December 2015 is US$0.1 million (2014: US$0.2 million).

Performance Share Plan ("PSP")

On 13 November 2013, the Company awarded 5,429,689 performance Shares to its employees under the PSP scheme. 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 21 July 2014, 1,809,898 performance Shares vested and ordinary Shares were issued (Note 17). On 25 June 2014 and 31 December 2014, the company awarded additional 1,713,111 and 3,473,737 performance Shares to its employees. The Shares will be awarded to selected employees and directors of the Company when certain conditions, which have been predetermined, are achieved during 5 years vesting period.

On 17 March 2015 and 9 November 2015, the company awarded additional 647,325 to employees and 11,613,474 Shares to employees and directors respectively. On 20 July 2015 and 31 December 2015, 2,025,674 and 3,916,635 performance Shares vested and ordinary Shares were issued (Note 17).

As at 31 December 2015, the employee share option reserve for the PSP amounts to US$1.7 million (2014: US$1.7 million).

There has been no cancellation or modification to the employee share-based payments in 2015 and 2014.

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.

VSA

	2015	2014
Risk free rate (%)	0.8% - 1.4%	0.6% – 0.9%
Expected volatility (%)	33% - 66%	29% - 46%
Annual employee exit rate (%)	1% – 3%	3% – 5%

PSP

Risk free rate (%)	0.9% – 1.4%	1.2% – 1.6%
Expected volatility (%)	35% – 48%	40% – 44%
Annual employee exit rate (%)	1% – 3%	3% – 5%

23 | DERIVATIVES LIABILITIES

Concurrent with the issue of 2017 Notes and 2018 Notes under the MTN Program (Note 19), the Group entered into the following cross currency swaps with total notional contract amount of US$ 263.8 million:

a) Cross currency swaps of a similar duration to convert the 3-Year S$ fixed rate liability of S$130.0 million to US$ floating rate liability of US$103.3 million;

b) Cross currency swaps of a similar duration to convert the 4-Year S$ fixed rate liability of S$200.0 million to US$ floating rate liability of US$160.5 million;

Under the cross currency swaps, the Group agreed with the swap counterparties to exchange S$ for US$ at the start date of the swaps and vice versa at the maturity date. In addition, the Group will exchange US$ interest amounts for S$ interest amounts with the swap counterparties, at specified intervals during the tenor of the cross currency swaps, calculated by reference to the respective contracted notional principal amounts. The cumulative fair value changes of the risk hedged was included in the carrying value of the MTN (Note 19). The cross currency swaps will mature between 2017 and 2018.

The decrease in fair value of the cross currency swaps of US$16.2 million (2014: US$19.4 million) has been recognised in other operating expenses and offset with the gain due to hedge of US$17.9 million (2014: US$16.4 million) that has been adjusted to the carrying amount of the 2017 and 2018 Notes.

	FAIR VALUES			
GROUP AND COMPANY	**2015**		**2014**	
	ASSETS	LIABILITIES	ASSETS	LIABILITIES
	US$	US$	US$	US$
Current				
Fair value hedges				
– Cross currency swaps	–	35,545,033	–	19,388,642
Total	**–**	**35,545,033**	**–**	**19,388,642**

24 | COMMITMENTS

(a) Operating lease commitments

The Group has entered into non-cancellable commercial property leases for the office 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

	2015	**2014**
	US$	US$
Within one year	733,418	807,275
After one year but not more than five years	1,218,606	213,125
	1,952,024	**1,020,400**

(b) 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$57.8 million (2014: US$58.2 million). As at 31 December 2015, there are optional capital commitments of US$62.5 million (2014: US$58.6 million).

At the reporting date, the Group's outstanding minimum exploration commitments will fall due as follows:

GROUP

	2015	**2014**
	US$	US$
Within one year	11,100,000	7,826,250
Within two to five years	46,665,978	50,362,500
	57,765,978	**58,188,750**

25 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

	2015	2014
	US$	US$
Salaries and bonus	7,380,000	10,892,157
Central Provident Fund contributions	61,850	67,199
Share-based payments	1,046,678	1,561,676
	8,488,528	**12,521,032**
Comprising amounts paid to:		
Directors of the Company	3,766,301	4,801,636
Other key management personnel	4,722,227	7,719,396
	8,488,528	**12,521,032**

26 FAIR VALUE OF FINANCIAL INSTRUMENTS

(a) Fair value hierarchy

The Group categorises fair value measurement using a fair value hierarchy that is dependent on the valuation inputs used as follows:

- Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date
- Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices), and
- Level 3 – Unobservable inputs for the asset or liability

Fair value measurements that use inputs of different hierarchy levels are categorised in its entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement.

(b) Assets and liabilities measured at fair value

The following table shows an analysis of assets and liabilities measured at fair value at the end of the reporting period:

GROUP

	NOTE	LEVEL 1	LEVEL 2	LEVEL 3	TOTAL
		US$	US$	US$	US$
2015					
Financial liabilities					
Derivative liabilties					
– Cross currency swaps	23	–	35,545,033	–	35,545,033
Loans and borrowings					
– Fair value of hedged risk of Multi-currency Medium Term Notes	19	–	(34,296,796)	–	(17,868,600)
		–	**1,248,237**	**–**	**1,248,237**
2014					
Financial liabilities					
Derivative liabilties					
– Cross currency swaps	23	–	19,388,642	–	19,388,642
Loans and borrowings					
– Fair value of hedged risk of Multi-currency Medium Term Notes	19	–	(16,428,196)	–	(16,428,196)
		–	**2,960,446**	**–**	**2,960,446**

(c) 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:

Cross currency swaps and hedged risk

Swap contracts and hedged risks are valued using a valuation technique with market observable inputs, which includes forward pricing and swap models using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, interest rate curves and forward rate curves.

(d) Fair value of financial instruments by classes that are not carried at fair value and whose carrying amounts are not reasonable approximation of fair value

The fair value of financial assets and liabilities by classes that are not carried at fair value and whose carrying amounts are not reasonable approximation of fair value are as follows:

GROUP	2015		2014	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	US$	US$	US$	US$
Financial assets				
Equity securities, at cost	216,000	*	–	–

* Investment in equity securities carried at cost

Fair value information has not been disclosed for the Group's investment in equity securities that are carried at cost because fair value cannot be measured reliably. These equity securities are not quoted on any market and does not have any comparable industry peer that is listed.

27 | 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, and liquidity 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 is the risk of loss that may arise on outstanding financial instruments should a counterparty default on its obligations. 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 carrying amount of loans and borrowings recognised in the consolidated statement of financial position and corporate guarantees

Credit risk concentration profile

At the reporting date, approximately 57% (2014: 34%) of the Group's receivables arises from the Group's working interest in G10/48 concession, G11/48 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, investment securities and derivatives 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 (Trade and other receivables).

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. As at 31 December 2015 and 2014, the Group has insignificant financial instruments that are exposed to interest rate risk.

Liquidity risk

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.

The table below summaries the maturity profile of the Group's financial assets and liabilities at the reporting date based on contractual undiscounted repayments obligations.

GROUP	ONE YEAR OR LESS	ONE TO FIVE YEARS	MORE THAN FIVE YEARS	TOTAL
	US$	US$	US$	US$
2015				
Financial assets				
Trade and other receivables	66,226,269	–	–	66,226,269
Cash and bank balances	29,351,634	–	–	29,351,634
Total undiscounted financial assets	**95,577,903**	**–**	**–**	**95,577,903**
Financial liabilities				
Trade and other payables	31,911,859	34,843,307	–	66,755,166
Accrued operating expenses	38,015,365	–	–	38,015,365
Loans and borrowings	–	304,571,912	–	304,571,912
Employee benefit liability	–	–	1,888,841	1,888,841
Total undiscounted financial liabilities	**69,927,224**	**339,415,219**	**1,888,841**	**411,231,284**
Total net undiscounted financial assets/(liabilities)	**20,650,679**	**(339,415,219)**	**(1,888,841)**	**(315,653,381)**
2014				
Financial assets				
Trade and other receivables	61,012,794	–	–	61,012,794
Cash and bank balances	51,334,088	–	–	51,334,088
Total undiscounted financial assets	**112,346,882**	**–**	**–**	**112,346,882**
Financial liabilities				
Trade and other payables	27,393,025	–	–	27,393,025
Accrued operating expenses	20,191,470	–	–	20,191,470
Loans and borrowings	–	257,440,512	–	257,440,512
Employee benefit liability	–	–	1,483,647	1,483,647
Total undiscounted financial liabilities	**47,584,495**	**257,440,512**	**1,483,647**	**306,508,654**
Total net undiscounted financial assets/(liabilities)	**64,762,387**	**(257,440,512)**	**(1,483,647)**	**(194,161,772)**

The table below shows the contractual expiry by maturity of the Group's contingent liabilities and commitments. The maximum amount of the corporate guarantee for the KEHCL Callable Bonds and KEAL Revolving Credit Facility (Note 19) is allocated to the earliest period in which the guarantee could be called.

GROUP	ONE YEAR OR LESS	ONE TO FIVE YEAR	MORE THAN FIVE YEARS	TOTAL
	US$	US$	US$	US$
2015				
Corporate guarantees	2,102,047	7,500,000	770,000	10,372,047
2014				
Corporate guarantees	1,000,000	7,500,000	770,000	9,270,000

28 | CAPITAL MANAGEMENT

Capital includes debt and equity items as disclosed in the table below.

The primary objective of the Group's capital management is to ensure that it maintains healthy capital ratios in order to support its business and maximise shareholder value.

The Group always seeks to optimise its overall capital structure and will actively pursue viable options to access the debt and/or equity capital markets and to refinance, where necessary, existing debt obligations in light of changes in economic conditions, among other things.

The Group monitors capital using a gearing ratio, which is net debt divided by total capital plus net debt. The Group's policy is to keep the gearing ratio between 30% and 50%.

GROUP

	NOTE	2015 US$	2014 US$
Loans and borrowings	19	304,571,912	257,440,512
Equity attributable to the owners of the Company		502,083,862	418,966,993
Capital and net debt		**806,655,774**	**676,407,505**
Gearing ratio		**38%**	**38%**

29 | 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	
	2015 US$	2014 US$	2015 US$	2014 US$
Bangladesh	13,325,160	17,834,862	39,490,847	40,535,469
Cambodia	–	–	90,851,165	88,697,969
Indonesia	–	–	221,976,395	90,290,422
Thailand	46,846,039	57,070,367	462,376,992	371,022,089
Vietnam	–	–	80,960,633	40,020,407
	60,171,199	**74,905,229**	**895,656,032**	**630,566,356**

Non-current assets information presented above consists of exploration and evaluation assets, oil and gas properties and intangible assets as presented in the consolidated statement of financial position.

Information about major customers

The Group identifies a major customer as one who contributes to 10% or more of the total revenue. As at 31 December 2015, revenue from four major customers contributed to 45%, 22%, 18% and 15% (2014: 38%, 24%, 25% and 13%) of the total revenue, respectively.

30 | AUTHORISATION OF CONSOLIDATED FINANCIAL STATEMENTS FOR ISSUE

The consolidated financial statements for the year ended 31 December 2015 were authorised for issue in accordance with a resolution of the Directors on 15 March 2016.

Shareholding Statistics

Total number of issued Shares	:	1,490,051,245
Class of Shares	:	Ordinary Shares of US$0.00125 par value
Voting rights	:	1 vote per ordinary Share

Analysis of shareholdings as at 18 March 2016:

SIZE OF SHAREHOLDINGS	NUMBER OF SHAREHOLDERS	%	NUMBER OF SHARES	%
1 – 99	94	4.50	667	0.00
100 – 1,000	143	6.84	106,651	0.01
1,001 – 10,000	787	37.64	4,924,424	0.33
10,001 – 1,000,000	1,041	49.78	73,133,045	4.89
1,000,001 & above	26	1.24	1,415,886,458	94.77
Total	**2,091**	**100.00**	**1,494,051,245**	**100.00**

TOP TWENTY SHAREHOLDERS AS AT 18 MARCH 2016:

NO.	NAME OF SHAREHOLDER	NUMBER OF SHARES	%
1.	BNP Paribas Nominees Singapore Pte Ltd	598,263,893	40.04
2.	Merrill Lynch (S) Pte Ltd	560,579,775	37.52
3.	Citibank Nominees Singapore Pte Ltd	54,819,754	3.67
4.	BNP Paribas Securities Services	38,795,480	2.60
5.	DBSN Services Pte Ltd	36,361,816	2.43
6.	Morgan Stanley Asia (S) Securities Pte Ltd	23,752,100	1.59
7.	Raffles Nominees (Pte) Ltd	15,289,454	1.02
8.	HSBC (Singapore) Nominee Pte Ltd	14,520,656	0.97
9.	United Overseas Bank Nominees Pte Ltd	12,347,580	0.83
10.	DBS Nominees Pte Ltd	8,300,504	0.56
11.	Waterworth Pte Ltd	8,000,000	0.54
12.	Lee Yuen Shih	7,893,900	0.53
13.	Phillip Securities Pte Ltd	6,828,186	0.46
14.	OCBC Securities Private Ltd	6,695,632	0.45
15.	DBS Vickers Securities (S) Pte Ltd	3,457,000	0.23
16.	Teo Chiang Song	3,200,000	0.21
17.	UOB Kay Hian Pte Ltd	3,171,540	0.21
18.	Radtke Investments L.P.	2,000,000	0.13
19.	Maybank Kim Eng Securities Pte Ltd	1,860,376	0.13
20.	Citibank Consumer Nominees Pte Ltd	1,798,000	0.12
		1,407,935,646	**94.24**

SUBSTANTIAL SHAREHOLDERS AS AT 18 MARCH 2016:

	HOLDINGS REGISTERED IN NAME OF SUBSTANTIAL SHAREHOLDERS OR NOMINEES		HOLDINGS IN WHICH SUBSTANTIAL SHAREHOLDERS ARE DEEMED TO HAVE AN INTEREST IN		TOTAL SHAREHOLDING	
	NO. OF SHARES	%	NO. OF SHARES	%	NO. OF SHARES	%
KrisEnergy Holdings Ltd	560,505,269	37.52	–	–	560,505,269	37.52
First Reserve Fund XII L.P.	–	–	560,505,269[1]	37.52	560,505,269	37.52
First Reserve GP XII, L.P.	–	–	560,505,269[1]	37.52	560,505,269	37.52
First Reserve GP XII Limited	–	–	560,505,269[1]	37.52	560,505,269	37.52
William Macaulay	–	–	560,505,269[1]	37.52	560,505,269	37.52
Devan International Limited	598,263,893	40.04	–	–	598,263,893	40.04
Keppel Oil & Gas Pte Ltd	–	–	598,263,893[2]	40.04	598,263,893	40.04
Kepventure Pte Ltd	–	–	598,263,893[2]	40.04	598,263,893	40.04
Keppel Corporation Limited	–	–	598,263,893[3]	40.04	598,263,893	40.04
Temasek Holdings (Private) Limited	–	–	598,263,893[3]	40.04	598,263,893	40.04

Notes

1 First Reserve Fund XII L.P. ("FR XII"), First Reserve GP XII, L.P. ("FR GP XII"), First Reserve GP XII Limited ("FR GP XII Limited") and William Macaulay are deemed under Section 4 of the Securities and Futures Act, Chapter 289 of Singapore ("SFA") to have an interest in the Shares held by KrisEnergy Holdings Ltd. ("KEHL") as:
- (a) FR XII is the holding company of KEHL;
- (b) FR XII is managed by FR GP XII;
- (c) FR GP XII is managed by FR GP XII Limited; and
- (d) William Macaulay has the ability to appoint directors of FR GP XII Limited

2 Keppel Oil and & Gas Pte Ltd. ("Keppel O&G"), Kepventure Pte Ltd ("KepVenture"), Keppel Corporation Limited ("Keppel Corp")are deemed under Section 4 of the SFA to have an interest in the Shares held by Devan International Limited ("Devan") as:
- (a) Devan is a wholly owned subsidiary of Keppel O&G;
- (b) Keppel O&G is a wholly owned subsidiary of Kep Venture; and
- (c) KepVenture a wholly owned subsidiary of Keppel Corp

3 Temasek Holdings (Private) Limited ("Temasek") is deemed under Section 4 of the SFA to have an interest in the Shares held by Devan as:
- (a) Devan is a wholly owned subsidiary of Keppel O&G;
- (b) Keppel O&G is a wholly owned subsidiary of KepVenture;
- (c) KepVenture a wholly owned subsidiary of Keppel Corp; and
- (d) Temasek has more than 20% interest in Keppel Corp, an independently managed Temasek portfolio company

Public Shareholders

Based on the information available to our Company as at 18 March 2016, approximately 21.75% 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 18 March 2016, the Company does not hold any treasury shares.

Summary of Qualified Person's Report (NSAI)

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG · MIKE K. NORTON
P. SCOTT FROST · DAN PAUL SMITH
JOHN G. HATTNER · JOSEPH J. SPELLMAN
J. CARTER HENSON, JR. · DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

January 21, 2016

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, 2015, 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, Wassana and Wassana Satellite Field Area, and Nong Yao Field, offshore Thailand; Lengo Field, offshore Indonesia; Block A Aceh, onshore Indonesia; and Bangora Field, onshore Bangladesh. Also as requested, we have estimated the development pending contingent resources and cash flow, as of December 31, 2015, to the KrisEnergy interest in certain discoveries located offshore Indonesia and offshore Cambodia and the development unclarified contingent resources, as of December 31, 2015, to the KrisEnergy working interest in certain other discoveries located offshore Thailand, offshore and onshore 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 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. The tables following the definitions set forth our estimates of reserves and contingent resources, by category, to the KrisEnergy interest for each asset area.

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, 2015, to be:

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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	35,867.6	262,205.4	9,972.6	53,483.2	62,108.8	77,204.6
Proved Developed Non-Producing	2,419.7	12,410.6	1,017.1	575.2	41,790.9	35,410.5
Proved Undeveloped	4,715.8	64,636.9	2,767.4	14,333.5	60,553.6	43,386.9
Proved (1P)	43,003.1	339,252.9	13,757.1	68,391.8	164,453.3	156,002.0
Probable	117,742.9	1,442,676.2	16,435.3	385,849.7	890,516.1	415,501.3
Proved + Probable (2P)	160,746.0	1,781,929.1	30,192.4	454,241.5	1,054,969.3	571,503.3
Possible	38,125.4	275,271.3	10,278.9	51,276.4	324,267.9	195,776.0
Proved + Probable + Possible (3P)	198,871.4	2,057,200.4	40,471.3	505,518.0	1,379,237.3	767,279.3

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, Aceh community development fund payments, ExxonMobil Indonesia overriding royalty interest, and income taxes.

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.

The estimates of reserves shown in this report are for proved, probable, and possible reserves. 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, Aceh community development fund payments, ExxonMobil Indonesia overriding royalty interest, 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.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered

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mature enough for commercial development because of one or more contingencies. The discoveries assessed in this report have been subclassified as development pending or development unclarified. The 2007 PRMS defines a development pending discovery as a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future and 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) commitment of the license partners to develop the resources, (2) submission and approval of a Plan of Development, Production Area Application, or Production Permit Application, (3) completion of a gas sales agreement, (4) collection of additional technical data, to be gathered through delineation wells and flow tests, to establish commercial viability, (5) extension of the production sharing contract, and (6) finalization of a plan to develop the resources. The costs required to resolve these contingencies have not been included in this report; estimates of cash flow are based on the assumption that all applicable contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for the development unclarified contingent resources. 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 and net contingent cash flow to the KrisEnergy interest in these discoveries, as of December 31, 2015, to be:

Subclassification/ Category	Gross (100%) Contingent Resources		Working Interest Contingent Resources		Net Contingent Cash Flow[1] (M$)	
	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Discounted At 10%
Development Pending						
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	8,627.1	95,395.9	4,509.8	51,180.1	129,975.3	44,928.9
High Estimate (3C)	15,099.5	166,314.1	7,892.9	88,559.7	323,924.8	153,934.6
Development Unclarified						
Low Estimate (1C)	4,283.9	765,184.1	2,174.9	315,834.4	[2]	[2]
Best Estimate (2C)	7,721.3	1,231,426.7	4,089.5	553,363.0	[2]	[2]
High Estimate (3C)	34,476.1	1,885,476.3	12,571.5	831,296.3	[2]	[2]

Note: Contingent resources are the arithmetic sum of multiple asset-level probability distributions.

[1] Net contingent cash flow is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, value-added taxes, carried costs and reimbursements associated with local participation, head office overhead, and income taxes.

[2] 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.

The oil volumes shown include crude oil and condensate.

The contingent resources shown in this report have been estimated using probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as

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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.

Gross contingent revenue for the development pending discoveries is KrisEnergy's share of the gross (100 percent) revenue from the properties after deductions for royalties. Net contingent cash flow is after additional deductions for KrisEnergy's share of capital costs, abandonment costs, operating expenses, value-added taxes, carried costs and reimbursements associated with local participation, head office overhead, and income taxes. The net contingent cash flow has been discounted at an annual rate of 10 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

ECONOMIC PARAMETERS

As requested, this report has been prepared using oil and gas price parameters specified by KrisEnergy. Oil prices for the reserves and development pending contingent resources are based on the average forecast for Brent Crude prices from an aggregation of several independent public forecasts and are adjusted by field area for quality, transportation fees, and market differentials. The oil prices, before adjustments, are shown in the following table:

Period Ending	Oil Price ($/Barrel)
12-31-2016	57.00
12-31-2017	66.00
12-31-2018	70.00
Thereafter	86.00

Gas prices for Block B8/32 and Block B9A reserves for January through March 2016 are based on the Tantawan Gas Sales Agreement price of $3.852 per MMBTU and are adjusted by field area for energy content. Gas prices starting in April 2016 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)
3-31-2016	3.852
12-31-2016	4.027
12-31-2017	4.354
12-31-2018	4.500
Thereafter	5.082

The gas price for Bangora Field reserves is the contract price of $2.319 per MCF. The gas prices for Block A Aceh reserves are based on a contract sales price of $9.45 per MMBTU and an expected price of $8.50 per MMBTU for the surplus gas volumes; these prices are adjusted for energy content. Gas prices for Bangora Field and Block A Aceh are held constant throughout the lives of the properties.

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The gas prices for Lengo and East Lengo Fields and Dambus and Mangkok Discoveries are based on recent gas contracts in similar areas and are $7.000 per MMBTU; these prices are adjusted for energy content. Gas prices for Lengo and East Lengo Fields and Dambus and Mangkok Discoveries are escalated 3 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, 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. 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 and development pending contingent resources 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. 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,

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categorize, and estimate volumes in accordance with the 2007 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 21, 2016

By:
Allen E. Evans, Jr., P.G. 1286
Vice President

Date Signed: January 21, 2016

PSF:TDL

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

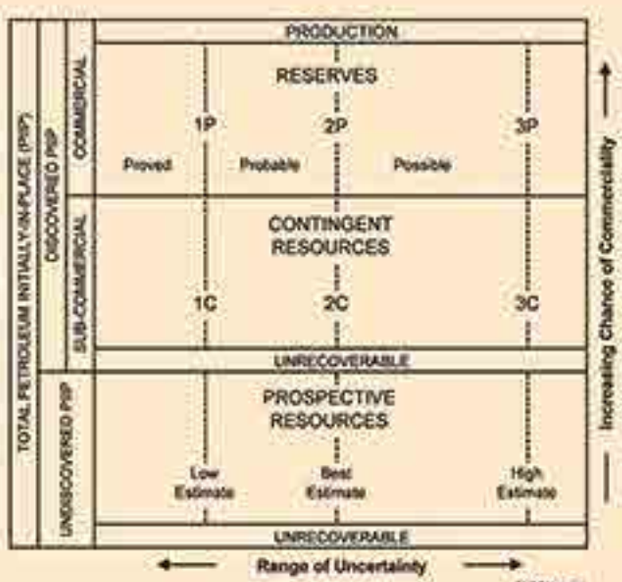

Figure 1-1: Resources Classification Framework.

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

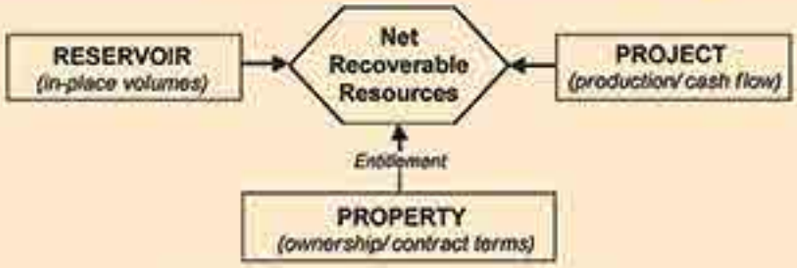

Figure 1-2: Resources Evaluation Data Sources

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

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Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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Class/Sub-Class	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

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SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2015

Country/Asset/Category	Gross (100%) Reserves Oil (MBBL)	Gross (100%) Reserves Gas (MMCF)	Working Interest Reserves[1] Oil (MBBL)	Working Interest Reserves[1] Gas (MMCF)	Net Reserves[2] Oil (MBBL)	Net Reserves[2] Gas (MMCF)	Future Net Revenue[3] (M$) Total	Future Net Revenue[3] (M$) Present Worth at 10%
Offshore Thailand								
Blocks B8/32 and B9A								
Proved Developed Producing	20,411.2	99,262.7	946.0	4,600.3	859.8	4,270.9	(40,067.6)[4]	(21,939.7)[4]
Proved Developed Non-Producing	1,185.5	12,410.6	54.9	575.2	47.7	517.5	5,099.1	4,440.7
Proved Undeveloped	766.9	19,938.8	35.5	924.1	32.7	862.0	2,747.5	1,574.8
Proved (1P)	22,363.5	131,612.1	1,036.4	6,099.6	940.2	5,650.4	(32,220.9)[4]	(15,924.2)[4]
Probable	91,805.5	537,108.7	4,254.7	24,892.3	3,791.3	22,579.0	124,536.6	78,385.4
Proved + Probable (2P)	114,169.0	668,720.7	5,291.2	30,991.9	4,731.5	28,229.3	92,315.7	62,461.2
Possible	22,738.5	151,479.3	1,053.8	7,020.3	901.7	6,141.6	49,998.3	23,546.1
Proved + Probable + Possible (3P)	136,907.5	820,200.0	6,345.0	38,012.2	5,633.2	34,371.0	142,313.9	86,007.3
Block G6/48, Rossukon Field								
Probable	11,700.0	0.0	3,510.0	0.0	3,260.5	0.0	52,301.7	31,202.3
Proved + Probable (2P)	11,700.0	0.0	3,510.0	0.0	3,260.5	0.0	52,301.7	31,202.3
Possible	4,100.0	0.0	1,230.0	0.0	1,115.1	0.0	26,857.0	19,366.1
Proved + Probable + Possible (3P)	15,800.0	0.0	4,740.0	0.0	4,375.6	0.0	79,158.7	50,568.4
Block G10/48, Wassana and Wassana Satellite Field Area								
Proved Developed Producing	8,291.0	0.0	7,379.0	0.0	6,858.7	0.0	68,463.2	68,124.7
Proved Developed Non-Producing	1,029.2	0.0	916.0	0.0	839.4	0.0	34,492.4	29,096.2
Proved Undeveloped	2,757.4	0.0	2,454.1	0.0	2,215.0	0.0	37,785.4	28,191.5
Proved (1P)	12,077.6	0.0	10,749.1	0.0	9,004.2	0.0	140,740.9	125,412.4
Probable	6,657.0	0.0	5,924.7	0.0	5,429.2	0.0	140,837.8	108,237.4
Proved + Probable (2P)	18,734.6	0.0	16,673.8	0.0	15,333.4	0.0	281,578.7	233,649.8
Possible	7,839.2	0.0	6,976.9	0.0	6,376.7	0.0	149,079.9	101,775.8
Proved + Probable + Possible (3P)	26,573.8	0.0	23,650.7	0.0	21,710.0	0.0	430,658.6	335,425.6
Block G11/48, Nong Yao Field								
Proved Developed Producing	6,692.9	0.0	1,505.9	0.0	1,407.1	0.0	8,066.9	10,005.2
Proved Developed Non-Producing	205.0	0.0	46.1	0.0	42.1	0.0	2,199.4	1,873.6
Proved Undeveloped	1,061.9	0.0	238.9	0.0	222.5	0.0	9,083.1	6,669.2
Proved (1P)	7,959.8	0.0	1,791.0	0.0	1,671.6	0.0	19,349.4	18,548.0
Probable	1,940.7	0.0	436.7	0.0	405.4	0.0	12,635.3	10,548.3
Proved + Probable (2P)	9,900.6	0.0	2,227.6	0.0	2,077.0	0.0	31,984.7	29,096.3
Possible	2,073.2	0.0	466.5	0.0	432.7	0.0	14,884.4	11,856.3
Proved + Probable + Possible (3P)	11,973.8	0.0	2,694.1	0.0	2,509.7	0.0	46,869.1	40,952.5

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, 30.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 22.5000 percent in Block G11/48, 42.5000 percent in the Bulu PSC, 41.6666 percent in Block A Aceh, 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 remunerator benefit, value-added taxes, Aceh community development fund payments, ExxonMobil Indonesia overriding royalty interest, and income taxes.

(4) Future net revenue is negative after deducting estimated abandonment costs.

(5) Reserves are negative because of a combination of factors including varying estimated ultimate recoveries for each field in the low, best, and high estimate cases; differing gas energy content by field; the production sharing contract expiration date of August 31, 2031; fuel gas usage requirements; and daily and total contracted gas quantity constraints.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF RESERVES AND FUTURE NET REVENUE
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2015

Country/Asset/Category	Gross (100%) Reserves Oil (MBBL)	Gross (100%) Reserves Gas (MMCF)	Working Interest Reserves[1] Oil (MBBL)	Working Interest Reserves[1] Gas (MMCF)	Net Reserves[2] Oil (MBBL)	Net Reserves[2] Gas (MMCF)	Future Net Revenue[3] (M$) Total	Future Net Revenue[3] (M$) Present Worth at 10%
Offshore Indonesia								
Bulu PSC, Lengo Field								
Probable	0.0	357,850.8	0.0	152,086.6	0.0	109,252.1	215,776.7	79,038.4
Proved + Probable (2P)	0.0	357,850.8	0.0	152,086.6	0.0	109,252.1	215,776.7	79,038.4
Possible	0.0	60,495.4	0.0	25,710.5	0.0	14,825.4	45,536.1	23,346.2
Proved + Probable + Possible (3P)	0.0	418,346.2	0.0	177,797.1	0.0	124,077.6	261,312.8	102,384.6
Onshore Indonesia								
Block A Aceh								
Probable	5,291.2	381,909.0	2,204.7	159,128.5	1,055.2	124,536.0	309,471.2	89,358.9
Proved + Probable (2P)	5,291.2	381,909.0	2,204.7	159,128.5	1,055.2	124,536.0	309,471.2	89,358.9
Possible	1,194.2	(3,800.6)[4]	497.6	(1,583.6)[4]	131.0	(2,769.5)[4]	24,507.5	10,764.7
Proved + Probable + Possible (3P)	6,485.4	378,108.4	2,702.3	157,544.9	1,186.2	121,766.4	333,978.7	100,123.6
Onshore Bangladesh								
Block 9, Bangora Field								
Proved Developed Producing	472.5	162,942.8	141.8	48,882.8	54.5	27,074.3	25,646.3	21,014.4
Proved Undeveloped	129.6	44,698.1	38.9	13,409.4	16.5	7,029.6	10,937.6	6,951.4
Proved (1P)	602.2	207,640.8	180.6	62,292.3	70.9	34,104.0	36,583.9	27,965.9
Probable	348.5	165,807.7	104.5	49,742.3	28.1	22,235.1	34,056.8	18,730.6
Proved + Probable (2P)	950.7	373,448.5	285.2	112,034.6	99.0	56,339.1	71,540.7	46,696.5
Possible	180.2	67,097.3	54.0	20,129.2	17.4	9,958.8	13,404.7	5,120.9
Proved + Probable + Possible (3P)	1,130.8	440,545.8	339.2	132,163.7	116.4	66,297.9	84,945.5	51,817.3
Total								
Proved Developed Producing	35,867.6	262,205.4	9,972.6	53,483.2	9,180.2	31,345.3	62,108.8	77,204.6
Proved Developed Non-Producing	2,419.7	12,410.6	1,017.1	575.2	929.2	517.5	41,790.9	35,410.5
Proved Undeveloped	4,715.8	64,636.9	2,767.4	14,333.5	2,486.6	7,891.6	60,553.6	43,386.9
Proved (1P)	43,003.1	339,252.9	13,757.1	68,391.8	12,596.9	39,754.3	164,453.3	156,002.0
Probable	117,742.9	1,442,676.2	16,435.3	385,849.7	13,969.7	278,602.2	690,516.1	415,501.3
Proved + Probable (2P)	160,746.0	1,781,929.1	30,192.4	454,241.5	26,566.7	318,356.5	1,054,969.3	571,503.3
Possible	38,125.4	275,271.3	10,278.9	51,276.4	8,974.5	28,156.4	324,267.9	195,776.0
Proved + Probable + Possible (3P)	198,871.4	2,057,200.4	40,471.3	505,518.0	35,531.1	346,512.9	1,379,237.3	767,279.3

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, 30.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 22.5000 percent in Block G11/48, 42.5000 percent in the Bulu PSC, 41.6666 percent in Block A Aceh, 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, Aceh community development fund payments, ExxonMobil Indonesia overriding royalty interest, and income taxes.

(4) Future net revenue is negative after deducting estimated abandonment costs.

(5) Reserves are negative because of a combination of factors including varying estimated ultimate recoveries for each field in the low, best, and high estimate cases; differing gas energy content by field; the production sharing contract expiration date of August 31, 2031; fuel gas usage requirements; and daily and total contracted gas quantity constraints.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF DEVELOPMENT PENDING
CONTINGENT RESOURCES AND CASH FLOW
KRISENERGY (ASIA) LTD INTEREST
AS OF DECEMBER 31, 2015

	Gross (100%) Contingent Resources		Working Interest Contingent Resources[1]		Net Contingent Resources[2]		Net Contingent Cash Flow[3] (M$)	
Country/Asset/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Total	Discounted at 10%
Offshore Indonesia								
East Muriah PSC, East Lengo Field								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	0.0	19,695.9	0.0	9,847.9	0.0	8,040.1	2,010.9	(3,724.3)[4][5]
High Estimate (3C)	0.0	46,865.1	0.0	24,432.6	0.0	16,896.1	30,244.6	7,343.1
Kutai PSC, Dambus and Mangkok Discoveries								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	90.1	75,700.0	49.2	41,332.2	30.1	27,517.3	90,869.3	37,842.3
High Estimate (3C)	146.8	117,449.0	80.2	64,127.1	39.9	38,166.7	134,341.9	55,412.1
Offshore Cambodia								
Block A, Platform A								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	8,537.1	0.0	4,460.6	0.0	3,584.0	0.0	37,095.0	10,810.9
High Estimate (3C)	14,952.7	0.0	7,812.8	0.0	5,945.0	0.0	159,338.2	91,179.4
Total[6]								
Low Estimate (1C)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Best Estimate (2C)	8,627.1	95,395.9	4,509.8	51,180.1	3,614.1	35,557.4	129,975.3	44,928.9
High Estimate (3C)	15,099.5	166,314.1	7,892.9	88,559.7	5,984.9	55,062.8	323,924.8	153,934.6

[1] KrisEnergy's current working interest is 50.0000 percent in the East Muriah PSC, 54.6000 percent in the Kutai PSC, and 52.2500 percent in Block A. It is anticipated that local participation will reduce the current working interest proportionately in the East Muriah PSC and the Kutai PSC based on the local participant obtaining a 10.0000 percent interest in the asset. Where applicable, working interest contingent resources are estimated based on the current working interest and net contingent cash flows are estimated based on the future reduced working interest.

[2] Net contingent resources are the portion of gross resources representing KrisEnergy's cash flow entitlement.

[3] Net contingent cash flow is after deductions for royalties and KrisEnergy's share of capital costs, abandonment costs, operating expenses, value-added taxes, carried costs and reimbursements associated with local participation, head office overhead, and income taxes.

[4] Future net revenue is negative after deducting estimated abandonment costs.

[5] Future discounted net contingent cash flow is negative after deducting estimated abandonment costs.

[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.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF DEVELOPMENT UNCLARIFIED CONTINGENT RESOURCES KRISENERGY (ASIA) LTD INTEREST AS OF DECEMBER 31, 2015

Country/Asset/Category	Gross (100%) Contingent Resources Oil (MBBL)	Gross (100%) Contingent Resources Gas (MMCF)	Working Interest Contingent Resources[1] Oil (MBBL)	Working Interest Contingent Resources[1] Gas (MMCF)
Offshore Thailand				
Block G6/48, Rossukon Field				
Low Estimate (1C)	0.0	11,476.9	0.0	3,443.1
Best Estimate (2C)	0.0	13,238.4	0.0	3,971.5
High Estimate (3C)	0.0	15,369.3	0.0	4,610.8
Block G10/48, Wassana and Wassana Satellite Fields				
Low Estimate (1C)	899.3	0.0	800.4	0.0
Best Estimate (2C)	1,361.5	0.0	1,211.8	0.0
High Estimate (3C)	1,957.5	0.0	1,742.2	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
Block G11/48, Angun Field				
Low Estimate (1C)	285.1	0.0	64.1	0.0
Best Estimate (2C)	663.8	0.0	149.4	0.0
High Estimate (3C)	21,066.8	0.0	4,740.0	0.0
Block G11/48, Mantana Field				
Low Estimate (1C)	0.0	4,922.7	0.0	1,107.6
Best Estimate (2C)	0.0	14,842.6	0.0	3,339.6
High Estimate (3C)	0.0	26,077.9	0.0	5,867.5
Block G11/48, Nong Yao Field				
Low Estimate (1C)	1,509.0	0.0	339.5	0.0
Best Estimate (2C)	1,854.2	0.0	417.2	0.0
High Estimate (3C)	2,239.6	0.0	503.9	0.0

(1) KrisEnergy's current working interest is 30.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 22.5000 percent in Block G11/48, 85.0000 percent in the Tanjung Aru PSC, 41.6666 percent in Block A Aceh, 52.2500 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 Tanjung Aru PSC 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.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF DEVELOPMENT UNCLARIFIED CONTINGENT RESOURCES KRISENERGY (ASIA) LTD INTEREST AS OF DECEMBER 31, 2015

Country/Asset/Category	Gross (100%) Contingent Resources Oil (MBBL)	Gross (100%) Contingent Resources Gas (MMCF)	Working Interest Contingent Resources[1] Oil (MBBL)	Working Interest Contingent Resources[1] Gas (MMCF)
Offshore Indonesia				
Tanjung Aru 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
Onshore Indonesia				
Block A Aceh				
Low Estimate (1C)	206.2	742,704.8	85.9	309,459.9
Best Estimate (2C)	848.8	1,065,155.9	353.7	443,814.3
High Estimate (3C)	2,417.3	1,559,266.3	1,007.2	649,693.2
Offshore Cambodia				
Block A, Platform B				
Low Estimate (1C)	762.1	0.0	398.2	0.0
Best Estimate (2C)	1,423.8	0.0	743.9	0.0
High Estimate (3C)	2,476.6	0.0	1,294.0	0.0
Block A, Platform C				
Low Estimate (1C)	145.6	0.0	76.1	0.0
Best Estimate (2C)	314.9	0.0	164.5	0.0
High Estimate (3C)	652.0	0.0	340.7	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)	4,283.9	765,184.1	2,174.9	315,834.4
Best Estimate (2C)	7,721.3	1,231,426.7	4,089.5	553,363.0
High Estimate (3C)	34,476.1	1,885,476.3	12,571.5	831,296.3

(1) KrisEnergy's current working interest is 30.0000 percent in Block G6/48, 89.0000 percent in Block G10/48, 22.5000 percent in Block G11/48, 85.0000 percent in the Tanjung Aru PSC, 41.6666 percent in Block A Aceh, 52.2500 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 Tanjung Aru PSC 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.

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 THIRD ANNUAL GENERAL MEETING OF KRISENERGY LTD. (THE "COMPANY") WILL BE HELD AT LEVEL 5, CINNAMON ROOM, NOVOTEL SINGAPORE CLARKE QUAY, 177A RIVER VALLEY ROAD, SINGAPORE 179031 ON 28 APRIL 2016 AT 9.00 A.M. TO TRANSACT THE FOLLOWING BUSINESS (THE "ANNUAL GENERAL MEETING"):

A	ORDINARY SHARES	ORDINARY RESOLUTION
1.	To receive and adopt the Directors' Report and the Audited Financial Statements for the financial year ended 31 December 2015 and the Auditor's Report thereon.	Resolution 1
2.	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 2
3.	To re-elect Mr. Richard Allan Lorentz, Jr., 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 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 4
5.	To re-elect Mr. Chan Hon Chew, a Director retiring pursuant to Article 124 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 5
6.	To approve the sum of US$1,140,000 (S$1,596,000) to be paid to all non-executive directors as Directors' fees for the financial year ended 31 December 2015. (2014: US$1,153,458.90 (S$1,499,496.57)) [See Explanatory Note 2]	Resolution 6
7.	To re-appoint Ernst & Young LLP as Auditors of the Company and to authorise the Directors to fix their remuneration.	Resolution 7

B SPECIAL BUSINESS ORDINARY RESOLUTION

To consider and, if thought fit, to pass the following resolutions as Ordinary Resolutions, with or without modifications:

8. 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: Resolution 8

(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]

9. To transact any other business as may properly be transacted at an annual general meeting.

By Order of the Board

KELVIN TANG / JENNIFER LEE
Joint Company Secretaries

13 April 2016, Singapore

Notice of Annual General Meeting

Notes

1. **Poll.**

   The Chairman of the Annual General Meeting will be exercising his right under Article 86(a) of the Memorandum and Articles of Association of the Company (the "Articles") to demand a poll in respect of the resolutions to be put to the vote at the Annual General Meeting and at any adjournment thereof. Accordingly, the Ordinary Resolutions proposed at the Annual General Meeting will be voted on by way of a poll.

2. **Depositors.**

   Under 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 48 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 may appoint not more than two persons (who shall be natural persons) to attend and vote in his place as proxy or proxies for CDP in respect of his shareholding, by completing and submitting the Depositor Proxy Form. 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 48 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. **Shareholders.**

   A shareholder of the Company (other than CDP) entitled to attend and vote at the Annual General Meeting 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, by completing and submitting the Shareholder Proxy Form.

   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 48 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 5

1. Detailed information on these Directors can be found in the section Board of Directors of the Company's Annual Report.

   (a) Mr. Duane Carl Radtke, upon re-election as a Director of the Company, will remain as the Chairman of the Investment Review Committee, a member of the Nominating Committee, the Remuneration Committee and the Technical Committee and is considered independent.

   (b) Mr. Richard Allan Lorentz, Jr. is considered non-independent and is an executive Director.

   (c) Mr. Tan Ek Kia, upon re-election as a Director of the Company, will remain as the Chairman of the Nominating Committee, a member of the Audit Committee and the Technical Committee and is considered independent.

   (d) Mr. Chan Hon Chew was appointed to the Board on 17 March 2016. Upon re-election as a Director of the Company, he will remain as a member of the Remuneration Committee and the Investment Review Committee. He is a nominee Director appointed by our indirect controlling shareholder, Keppel Corporation Ltd. He is considered non-independent and is a non-executive Director.

Resolution 6

2. USD to SGD exchange rates of 1.40:1 and 1.30:1 were used for the financial years ended 31 December 2015 and 31 December 2014, respectively.

Resolution 8

3. Resolution 8 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 8). The aggregate number of Shares which may be issued pursuant to Resolution 8 (including new Shares to be issued in pursuance of Instruments made or granted pursuant to Resolution 8) 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 8, 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 8 is passed; and (ii) any subsequent bonus issue, consolidation or subdivision of Shares.

Corporate Information

AS AT 17 MARCH 2016

BOARD OF DIRECTORS

Will Honeybourne	Non-Executive Chairman
John Koh	Lead Non-Executive Independent Director
Keith Cameron	Executive Director and Chief Executive Officer
Chris Gibson-Robinson	Executive Director
Richard Lorentz	Executive Director
Brooks Shughart	Non-Executive Director
Choo Chiau Beng	Non-Executive Director
Chan Hon Chew	Non-Executive Director
Duane Radtke	Non-Executive Independent Director
Jeff MacDonald	Non-Executive Independent Director
Tan Ek Kia	Non-Executive Independent Director
Alan Nisbet	Non-Executive Independent Director
Keith Pringle	Non-Executive Independent Director

AUDIT COMMITTEE

John Koh	Chairman
Tan Ek Kia	
Choo Chiau Beng	
Brooks Shughart	
Alan Nisbet	
Keith Pringle	

NOMINATING COMMITTEE

Tan Ek Kia	Chairman
John Koh	
Duane Radtke	
Jeff MacDonald	
Will Honeybourne	
Choo Chiau Beng	

REMUNERATION COMMITTEE

Jeff MacDonald	Chairman
Duane Radtke	
Brooks Shughart	
Alan Nisbet	
Keith Pringle	
Chan Hon Chew	

INVESTMENT REVIEW COMMITTEE

Duane Radtke	Chairman
Keith Cameron	
Brooks Shughart	
Alan Nisbet	
Keith Pringle	
Chan Hon Chew	

TECHNICAL COMMITTEE

Keith Pringle	Chairman
Tan Ek Kia	
Duane Radtke	
Jeff MacDonald	

JOINT COMPANY SECRETARIES

Kelvin Tang
Jennifer Lee

REGISTERED OFFICES

Intertrust Corporate Services (Cayman) Limited

190 Elgin Avenue, George Town, Grand Cayman, KY1–9005, Cayman Islands
T: +1 345 943 3100
F: +1 345 945 4757

REGISTERED OFFICE IN SINGAPORE

83 Clemenceau Avenue , #10–05 UE Square, Singapore 239920
T: +65 6838 5430
F: +65 6538 3622

SHARE TRANSFER AGENT

M&C Services Private Limited

112 Robinson Road, #05–01, Singapore 068902

AUDITORS

Ernst & Young LLP

Public Accountants and Chartered Accountants
One Raffles Quay North Tower, Level 18, Singapore 048583

AUDIT PARTNER

Toong Weng Sum, Vincent

Year appointed: 2011
Public Accountants and Chartered Accountants
One Raffles Quay North Tower, Level 18 Singapore 048583

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.
2017 Notes	S$130 million fixed-rate notes due January 2017.
2018 Notes	S$200 million fixed-rate notes due August 2018.
2C	Best estimate scenario of contingent resources.
2D seismic data	Geophysical data that depicts the subsurface strata in two dimensions (2D).
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.
bcf	Billion cubic feet.
boepd	Barrel(s) of oil equivalent per day.
bopd	Barrel(s) of oil per day.
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.
DDA	Depreciation, depletion and amortisation.
development well	A well drilled to obtain production from a proven oil or gas field.
E&P	Exploration and production.
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. It excludes exploration expenses and gives the true EBITDA of the firm.
Executive Director	A Director of our Group who performs an executive function.
First Reserve	First Reserve Management L.P., together with its affiliated funds.
FSO	Floating storage and offshore loading vessel.
gross reserves	The total volume of oil and/or gas anticipated to be commercially produced in the future.
jack-up rig	A type of mobile platform that consists of a buoyant hull fitted with a number of movable legs, capable of raising its hull over the surface of the sea.
km	Kilometre.
leads	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.
lifting costs	Costs to operate and maintain oil and gas wells and related equipment, and facilities to bring oil and gas to the surface.
mcf	Million cubic feet.
MME	Ministry of Mines and Energy in Cambodia.
mmbo	Million barrels of oil.
mmboe	Million barrels of oil equivalent.
mmcf	Million cubic feet.
mmcfd	Million cubic feet per day.
MOPU	Mobile offshore production unit.
MTN	Medium Term Note Program.
NSAI	Netherland, Sewell & Associates, Inc.
possible reserves	Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than probable reserves.
probable reserves	Those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than proved reserves but more certain to be recovered than possible reserves.
prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable exploration drilling target.
prospective resources	Those quantities of petroleum, which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
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.
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.
RCF	Revolving Credit Facility.
SGX-ST	Singapore Exchange Securities Trading Ltd.
sq. km	Square kilometre.
TVDSS	Total vertical depth subsea.
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 into account 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.

KrisEnergy Regional Offices

Bangladesh	NB Tower, Level 12 , 40/7, North Avenue, Gulshan 2, Dhaka 1212
Cambodia	No. 28, Street 310, Sangkat Boeung, Keng Kang 1, Khan Chamcar Monn, Phnom Penh, P.O. Box 1619
Indonesia	Talavera Office Park, 3rd Floor, Jalan Letjend TB., Simatupang, Kav. 22–26 , Cilandak, Jakarta 12430
Singapore	83 Clemenceau Avenue, #10–05, UE Square, Singapore 239920
Thailand	7F, Athenee Tower, No. 63, Wireless Road, Lumpini, Pathumwan, Bangkok 10330
Vietnam	19F, Bitexco Financial Tower, No. 2, Hai Trieu Street, Dist. 1 , Ho Chi Minh City

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