Central Petroleum Limited

2018 ANNUAL REPORT

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CORPORATE DIRECTORY

DIRECTORS

Martin Kriewaldt BA, LL.B (Hons 1st), FAICD (Life), Non-executive Chairman (appointed 23 October 2017)
Richard Cottee BA, LLB (Hons), Managing Director and Chief Executive Officer
Wrixon F Gasteen BE(Mining) (Hons), MBA (Distinction), Non-executive Director
Dr Peter S Moore BSc (Hons 1st), MBA, PhD, GAICD, Non-executive Director
Dr Sarah Ryan, PhD, BSc (Hons 1st), BSc, FTSE, MAICD, Non-executive Director (appointed 23 October 2017)
Tim Woodall, B. Econ, FCPA, GAICD, Non-executive Director (appointed 20 December 2017)

GROUP GENERAL COUNSEL AND JOINT COMPANY SECRETARY

Daniel C M White LLB, BCom, LLM

JOINT COMPANY SECRETARY

Joseph P Morfea FAIM, GAICD

REGISTERED OFFICE

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AUDITORS

PricewaterhouseCoopers
480 Queen Street, Brisbane, Queensland 4000

BANKERS

ANZ Banking Group
111 Eagle Street, Brisbane, Queensland 4000

SHARE REGISTER

Computershare Investor Services Pty Limited
117 Victoria Street, West End, Queensland 4101
Telephone: +61 7 3237 2110
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STOCK EXCHANGE LISTING

Central Petroleum Limited shares are listed on the Australian Securities Exchange under the code CTP.

CHAIRMAN’S LETTER

A MESSAGE FROM MARTIN KRIEWALDT

Dear Fellow Shareholders

Much has changed for Central since our last review in September 2017 covering the Financial Year 2017. Financial Year 2018 has seen the Company successfully complete a number of the objectives outlined at that time:

- Pipeline tariff reform in respect of monopolies either from ownership or from capacity hoarding. The significant reforms legislated will assist in bringing gas to the markets at reasonable returns to those who have invested capital in building the pipelines, but remove any incentive to leave that capacity idle for any reason;
- The signing of a Gas Sales Agreement (“GSA”) with Incitec Pivot Ltd (“IPL”) for the sale of a significant gas volume through 2019—which has helped to keep IPL’s Gibson Island Plant open—represents a significant step change in Central’s financial position;
- A separate agreement with IPL under which IPL funds Central under a $20 million farm-in to explore for gas in a new licence area in Queensland. Following that farm-in, IPL and Central will own any production and associated licences 50:50;
- Raising $27 million in funds through the rights issue to fund appraisal drilling and plant improvement;
- Commencement of work on upgrading our jointly owned Mereenie Plant and our Palm Valley Plant to deliver gas to new customers;
- Commencement of a drilling programme with the drilling of West Mereenie 26 and the preliminary work for permits to drill Palm Valley 13;
- The successful board succession programme with the appointment of Dr Sarah Ryan, Tim Woodall and me to the board, the retirement of Rob Hubbard from the board and its chairmanship and my appointment as replacement chairman. The board now has a wide range of oil industry experience as well as strong board experience.

The first three of these tasks are company-making for Central, given our gas producing assets are far removed from the main market for gas users. Following these reforms, we anticipate that Central’s gas can be sold into the east coast at a price that provides gas suppliers with an incentive for new exploration and also reduces the demand destruction that would have otherwise occurred. Importantly, Central’s gas can now be sold to Australian east coast users at a profit.

The alignment with IPL to explore for gas in Queensland is a wonderful example of management seeing the synergies of a combination of IPL and Central. The Queensland Government recognised the power of the combination in awarding the new area to Central and IPL.

As I write this, your Company is now fully focused on completing the plant upgrades necessary to make sure we deliver the gas we have sold to IPL and others. The drilling at Palm Valley is underway. On conclusion of the upgrades, your Company will be moving to the second phase of its strategy to grow its reserves and its sales to customers, the drilling being one aspect of that.

It has been a year of great achievements by the Central management team. I wish to thank all of them, including our new additions to the senior team, for their hard work throughout the year.

During the year and shortly after its conclusion, there have been two significant departures from Central.

Rob Hubbard chaired your Company through difficult times financially and the takeover bid. Neither task was easy. It is a credit to him that he remained at the helm during this period.

Richard Cottee has dominated the gas industry for many years and your Company has been fortunate to have his energy and strident advocacy as it progressed its strategy to get its gas to market profitably. His personality made it certain the Company view would be heard, despite our minnow status. His persistent pressure to achieve the reforms so necessary for the country and Central undoubtedly played a significant part in what has been achieved.

Richard leaves behind the completed first stage of Central’s strategy and the template for further growing the Company’s reserves, sales and, of course, value.

I thank them both for their contribution to the successful launch of a new player in the gas sales market, one with a big future, in my opinion.

Martin Kriewaldt
Chairman
Brisbane
28 September 2018

ACTING CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders

I would like to begin this letter by recognising the recent change that has taken place within the CEO role. Richard Cottee and the management team at Central have worked hard over the past five years to develop and position your Company's strategy of creating shareholder value by connecting its significant potential gas resources in the Northern Territory to the east coast gas market that remains in critical short supply. Richard provided leadership, energy and creativity that was critical in taking on such a transformative strategy, particularly the adept handling of many obstacles along the way. On a personal note, I thoroughly enjoyed taking this journey with him.

Following Richard's departure, I have taken up the role of Acting CEO. Together with the management team, Central remains committed to executing your Company's strategy to create value for all shareholders. Recognising the importance of our stakeholders and partners to our business, Central's team will continue to build on our engagement with, and commitment to, the traditional owners, the communities where we operate and our gas customers.

Over the past financial year, Central has materially progressed its Gas Acceleration Programme ("GAP") and strategy to be on the cusp of being a significant supplier into the east coast gas market following completion of the Northern Gas Pipeline ("NGP") scheduled for December 2018. Some of the notable milestones for the Company since the start of the 2018 financial year include:

1) **Gas Acceleration Programme:** Following our successful $27 million equity raise in September 2017, our approach to deliver the GAP evolved to include facility upgrades at Mereenie and Palm Valley, as well as appraisal drilling. With our target now in sight of having increased gas volumes (reserves and production capacity) available for sale into the NGP, Central remains fully focused on completing the facility upgrades and appraisal drilling programme as safely and as cost effectively as possible.

2) **IPL Gas Supply Agreement:** Central entered into a new GSA with IPL in June 2018 for 20 TJ/d commencing on completion of the NGP later this year. The IPL GSA is our first gas sales agreement into the east coast market and upon commencement, will contribute to an almost tripling of our gas sales under contract. This will fundamentally change the future financial performance of your Company, notably a significantly stronger cash flow.

3) **ATP 2031 Permit Award:** On 1 March 2018, the Queensland Department of Natural Resources, Mines and Energy announced Central was the preferred bidder for ATP 2031. This 77 km^2 permit is located within the prospective Queensland Surat Basin coal seam gas region and is approximately 28 km north-west of the town of Miles. The permit was formally granted to Central on 28 August 2018. It is contemplated that the acreage could ultimately help to support the long term viability of IPL's Gibson Island fertiliser facility in Queensland. As part of the arrangement, Central and IPL will establish a 50:50 joint venture whereby IPL will fund up to $20 million for the exploration programme.

4) **Local and Indigenous Employment:** Our employment philosophy, first established in March 2015, has achieved a good balance between local and Fly-in Fly-out ("FIFO") workers whilst continuing to deliver excellent safety and environmental performance. Our employment mix continues to be one third local indigenous, one third local non-indigenous and one third FIFO. This is a dramatic turnaround from September 2015 when Central assumed operatorship of Mereenie oil and gas field with its workforce at 93% FIFO.

5) **Pipeline Reforms:** There has been significant reform in the pipeline sector addressing both monopolistic pricing and capacity hoarding. The implementation of these reforms will largely occur over the next 12 months, during which time we would anticipate seeing the benefits of these reforms become visible to gas customers and suppliers. We have already seen some downward pressure in pipeline tariffs. Whilst in our view these reforms did not go far enough, we are optimistic that they will bring a material improvement to this critical part of the gas market;

6) **Management Team:** We have significantly augmented our management team in order to add capacity and capability to the team, deliver our current projects, and achieve our future growth objectives. This has included Ross Evans as Chief Operations Officer, Robin Polson as Chief Commercial Officer and Ben Visser as General Manager Operations.

In summary, we have been on a journey spanning several years with a focus to create real value for Central's shareholders. We have made enormous strides in delivering this vision and now stand poised to start reaping the benefit of this effort. In a year's time, we expect to be delivering significant volumes of gas into the east coast gas market, generating strong positive cash flows and embarking on new and exciting growth opportunities.

Leon Devaney

Leon Devaney
CEO (acting)
Brisbane
28 September 2018

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2018

Your Directors present their report on the consolidated entity, consisting of Central Petroleum Limited ("the Company", "Central" or "CTP") and the entities it controlled (collectively "the Group" or "the Consolidated Entity") at the end of, or during, the year ended 30 June 2018.

DIRECTORS

The names of the Directors of the Company in office during the financial year and until the date of this report are set out below. Directors were in office for this entire period unless otherwise stated.

Robert Hubbard (retired 14 May 2018)
Martin D Kriewaldt (appointed 23 October 2017)
Richard I Cottee
Wrixon F Gasteen
Peter S Moore
Sarah Ryan (appointed 23 October 2017)
Timothy R Woodall (appointed 20 December 2017)

PRINCIPAL ACTIVITIES

The principal activities of the Consolidated Entity constituting Central Petroleum Limited and the entities it controls consists of development, production, processing and marketing of hydrocarbons and associated exploration.

DIVIDENDS

No dividends were paid or declared during the financial year (2017: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

Operating Highlights

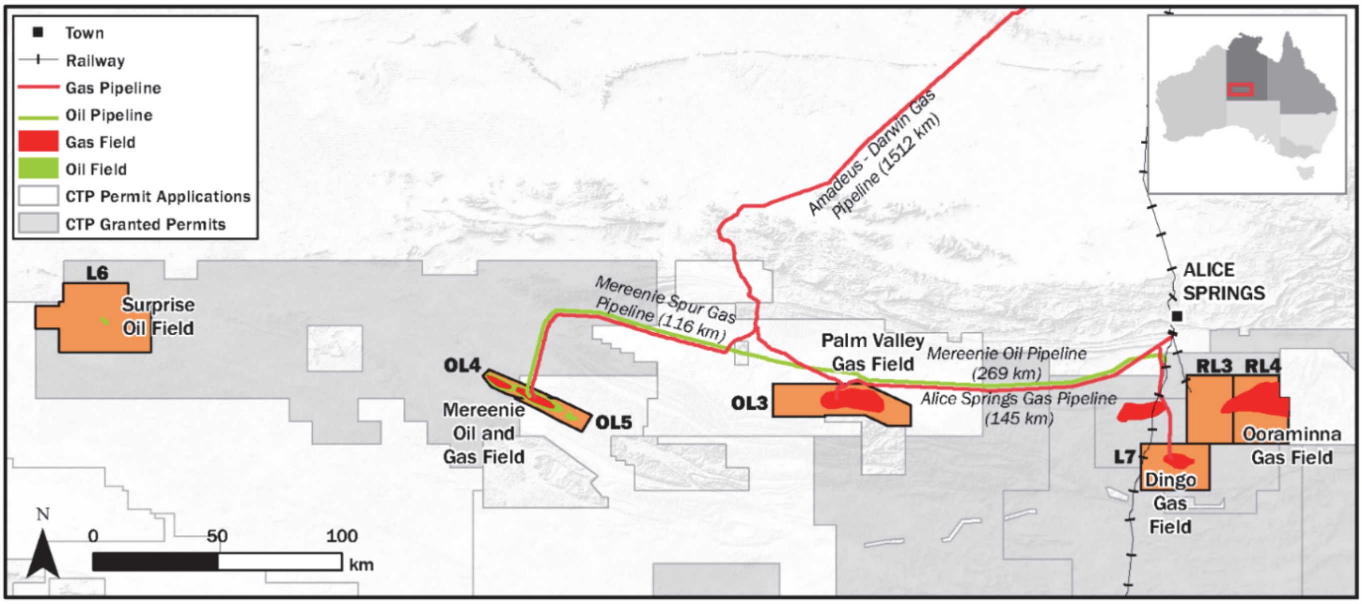
The Company's focus and achievements for the year were as follows:

- A 46% increase in gas sales volumes and a 41% increase in total sales revenue.
- Cash flow from operations of $5.2 million compared to a $0.2 million outflow in the prior year.
- An equity raising was successfully completed in September 2017 to support the Gas Acceleration Programme, raising $27 million.
- The ACCC granted authorisation for Mereenie Joint Marketing arrangements between Central and Macquarie Mereenie for three years.
- The Queensland Government announced that Central's wholly owned subsidiary, Central Petroleum Eastern Pty Ltd, was the preferred bidder for Queensland acreage (ATP(A) 2031). The permit lies within the north-eastern Walloon Fairway, surrounded by acreage held by QGC, Arrow and APLNG. Subsequent to year end, in August 2018, the permit was formally awarded to Central.
- West Mereenie 26 appraisal well spudded on 22 May 2018 and was in progress at 30 June 2018.
- A Gas Sales Agreement ("GSA") was executed with Incitec Pivot Limited ("IPL") whereby Central will deliver at least 20 TJ/day of gas to IPL on an ex-field basis from its Palm Valley and Mereenie fields. The gas will be delivered from the commencement of commercial operations on the Northern Gas Pipeline until 31 December 2019.
- A 50:50 joint venture arrangement for ATP(A) 2031 in Queensland was agreed with IPL, allowing the fast tracking of the Queensland acreage. IPL will contribute up to $20 million for appraisal drilling costs during the initial exploration period.
- The Company's management team was strengthened with the appointment of Ross Evans as Chief Operating Officer and Robin Polson as Chief Commercial Officer.
- Joint Venture approval was obtained for an expansion project at Mereenie to increase gas deliverability into the Northern Gas Pipeline ("NGP").
- Santos completed acquisition of 403 km of seismic data, infilling the previous 932 km of seismic acquired in 2016 and bringing the total to 1,335 km, meeting the requirements of the Stage 2 Farm-in in the Southern Amadeus Basin. The additional seismic lines reduce dip line spacing over the Dukas prospect to approximately 5 km between dip lines over the central prospect area, and approximately 10 km towards the flanks. Processing of the acquired seismic data has commenced and continues.
- Third party environmental audits were conducted at Palm Valley and Dingo with no non-conformances noted.

Operating Result

The Consolidated Entity had an operating loss after income tax for the year ended 30 June 2018 of $14.08 million (2017: loss of $24.73 million). Underlying EBITDA[1] for the Consolidated Entity was $2.21 million (2017: $0.32 million). In addition, non-cash share based payment expense included in the above results amounted to $1.62 million (2017: $2.25 million).

1 *EBITDA is earnings before interest, taxation, depreciation, amortisation and impairment.*



Granted Petroleum Production and Retention Licences in which the Company has an interest.

Key results for the reporting period were:

- **Sales Volumes** of 4,842 TJ of gas (2017: 3,322 TJ) and 105,619 barrels of crude oil (2017: 111,380 barrels). The increase in gas sales reflects a full year contribution from the Energy Developments Limited ("EDL") gas contract.
- **Sales Revenue** of $34.94 million, up 41% on the previous financial year, reflecting increased production as a result of the full year contribution of the EDL contract and an increase in the average realised oil price as a result of increases in world crude prices, but partly offset by a higher AUD:USD exchange rate.
- **Underlying loss**[1] of $13.67 million, down from an underlying loss of $15.27 million in the prior year, a 10% improvement.
- **Exploration expenditure** increased to $8.79 million in financial year 2018 from $1.90 million in financial year 2017 reflecting the appraisal drilling programme in progress at year end.
- **Net cash flow from operations** of $5.17 million, an improvement from a net cash outflow in 2017 of $0.2 million. Cash flows for financial year 2017 do not reflect any contribution from the new EDL sales contract which commenced in June 2017.

[1] Underlying loss after tax can be reconciled to statutory loss after tax as follows:

	2018 $ million	2017 $ million
Statutory loss after tax	(14.08)	(24.73)
Add/(less):		
R&D refunds	—	(0.63)
Restatement of financial liabilities[1]	0.41	9.49
Impairment of exploration assets	—	0.09
Impact with Total GLNG withdrawal from Southern Georgina Joint Venture (net of restoration liabilities)	—	(1.19)
One off items of corporate expenditure	—	1.70
Underlying loss after tax	**(13.67)**	**(15.27)**

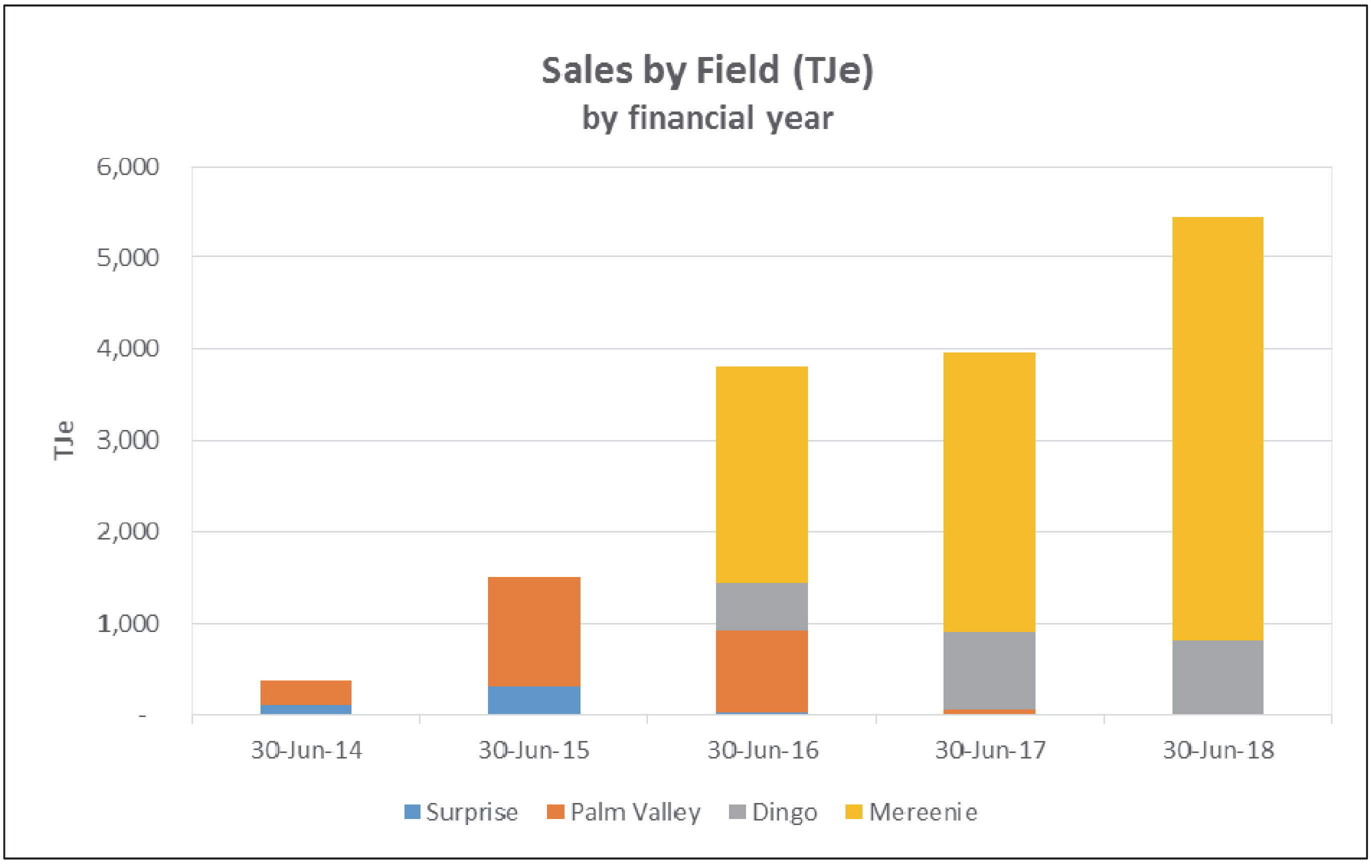
1 *Relates to a prepaid gas sales agreement containing a cash settlement option. If the cash settlement option is exercised, (instead of physical delivery of gas), payment will be satisfied out of future gas sales revenues from those gas sales agreements to which the cash settlement option is linked. Refer Note 3(b) to the Financial Statements for further explanation.*

Financial Review

The Company's financial position improved during the year ended 30 June 2018, with the underlying loss reduced by 10% on the previous financial year.

Key Metrics	2018	2017	Percentage Change*
Net Sales Volumes			
Oil (barrels)	105,619	111,380	(5)%
Natural Gas (TJ)	4,842	3,322	46%
Sales revenue ($ million)	34.94	24.79	41%
Underlying EBITDAX ($ million)	11.00	2.22	395%
Underlying EBITDA ($ million)	2.21	0.32	591%
Underlying Loss ($ million)	(13.67)	(15.27)	10%
Statutory loss (after tax)	(14.08)	(24.73)	43%
Cash ($ million)	27.22	5.48	397%

* *A positive percentage reflects an improvement over the previous year.*



Additional Information:

1. *Mereenie oil converted at 5.816 GJ/BOE*
2. *Central had no production prior to April 2014*

EBITDAX/EBITDA

Underlying earnings before interest, tax, depreciation and amortisation ("EBITDA") was $2.21 million, compared to $0.32 million in the prior year. Underlying EBITDA and exploration ("EBITDAX") was $11.00 million, compared to $2.22 million in the prior year.

Take or Pay

Gas sales from Dingo did not achieve full contracted volumes as the customer continued to take gas below the Annual Contract Quantity. Dingo Take-or-Pay cash receipts of $5.0 million were received for the contract year to 31 December 2017 and were not recognised as accounting revenue during the reporting period. This will be accounted for as revenue in future periods in accordance with the Group's revenue recognition policy (refer Note 1(e)(i)).

A reconciliation of underlying EBITDAX and EBITDA is shown below.

	2018 $ MILLION	2017 $ MILLION
Underlying loss after tax	(13.67)	(15.27)
Add/(less):		
Exploration	8.79	1.90
Net interest	7.85	7.81
Income tax	—	—
Depreciation and amortisation	8.03	7.78
Underlying EBITDAX[1]	**11.00**	**2.22**
Underlying EBITDA[1]	**2.21**	**0.32**

[1] *Underlying EBITDA and EBITDAX includes a non-cash share based payment expense of $1.62 million (2017: $2.25 million)*

Gas deliveries under the EDL contract commenced in June 2017. Underlying EBITDA for 2017 therefore reflects only one month supply under this new gas sales contract.

Sales Volumes

Mereenie gas sales volumes increased from 2017, reflecting a full year contribution from the EDL gas sales contract which commenced in June 2017.

Palm Valley gas field: In order to maintain operational efficiency and capacity across all assets the Palm Valley field was placed on 24-hour standby during 2016, with contracts being delivered from the Mereenie and Dingo fields.

Dingo gas field: In accordance with the Power and Water Corporation Gas Sales Agreement, revenue associated with Take-or-Pay during the 2017 calendar year was received in January 2018 but is yet to be recognised as income in accordance with the Group's revenue recognition accounting policy (refer Note 1(e)(i)).

Commodity Prices

Central's gas prices generally reflect long-term fixed gas pricing structures with CPI related escalation, and are therefore not impacted by global energy markets. In line with the increase in world crude oil prices, but partly offset by a higher Australian dollar, the average realised price of oil increased from the previous financial year.

Other Income

Other income for financial year 2018 included the sale of exploration permits amounting to $0.28 million along with $0.21 million from the sale of items of drilling inventory.

In the 2017 Total withdrew from the Southern Georgina Farmout. This resulted in the extinguishment of accrued liabilities amounting to $2.02 million recognised in other income during the 2017 financial year.

Restatement of Financial Liabilities

The statutory loss for the year ended 30 June 2018 includes a non-cash expense of $0.41 million (2017: $9.49 million) relating to the revaluation of financial liabilities associated with the Gas Sale and Prepayment Agreement with Macquarie Group which contains an option for Macquarie to elect a cash settlement in lieu of physical delivery of gas. The cash settlement amount, if opted for, is linked to the ex-field price of new Gas Sales Agreements entered into by the Group and supplied from the Mereenie, Dingo or Palm Valley fields. Refer to Note 3(b) to the financial statements for further explanation of this non-cash expense.

General and Administrative Expenses

General and administrative expenses net of recoveries decreased from $1.95 million in fiscal year 2017 to $0.60 million in fiscal year 2018. The decrease was largely a result of one off costs associated with the proposed Scheme of Arrangement incurred in the 2017 financial year.

Employee Benefits and Associated Costs

Employee costs, net of recoveries for operational and exploration activities, decreased to $4.06 million from $5.66 million in the previous financial year. Gross costs before recoveries increased 2.3% reflecting annual remuneration increases. Recoveries from exploration and production operations were higher as a result of increased activity including new capital projects and the appraisal drilling programme.

Cash

At 30 June 2018, consolidated cash and cash equivalents available totalled $27,222,845 (2017: $5,478,140), including $516,572 (30 June 2017: $396,972) held in joint venture bank accounts. Of this balance $1,782,026 relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2017: $1,421,848), including, but not limited to operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, and debt servicing.

Gearing

The consolidated debt ratio at 30 June 2018 was 0.49 (2017: 0.60). Debt ratio is defined as Total Debt / Total Assets. The Consolidated Entity's debt funding is supported by long-term gas sales contracts. Total borrowings decreased from $82.17 million at 30 June 2017 to $78.33 million at 30 June 2018 as the consolidated entity continues to make quarterly principal and interest repayments.

Capital Expenditure

Capital expenditure for fiscal year 2017 was $4.68 million, up from $0.96 million in 2017. Expenditure for the year included $2.37 million on the Mereenie Expansion project in progress at year end and $0.69 million on the Dingo glycol dehydration unit.

Comparative Data

The following table and discussion is a one year (and five year) comparative analysis of the Consolidated Entity's key financial information. The Statement of Financial Position information is as at 30 June each year and all other data is for the years then ended.

	2018 $ MILLION	2017 $ MILLION	2016 $ MILLION	2015 $ MILLION	2014 $ MILLION
Financial Data					
Operating revenue	34.94	24.79	23.86	10.31	3.72
Exploration expenditure	8.79	1.90	4.03	7.66	4.66
Loss after income tax	14.08	24.73	21.04	27.73	10.86
Equity issued during year	25.47	—	11.52	5.56	24.97
Property, plant and equipment	103.85	106.82	113.78	58.58	46.27
Borrowings	(78.33)	(82.17)	(85.70)	(47.46)	(23.76)
Net Assets (Total Equity)	7.06	(5.96)	16.52	23.15	43.07
Net Working Capital	17.19	0.73	5.33	(4.41)	2.78
Operating Data					
Gas Sales (GJ)	4,842,047	3,321,731	3,230,473	1,194,153	267,328
Oil Sales (barrels)	105,619	111,380	98,635	53,925	17,489
No. of employees at 30 June	89	83	83	58	51

Risks

Central was admitted to the ASX in 2006 and since that time has been exploring for, and more recently producing, oil and gas from onshore central Australia.

General Risks

As with most businesses, Central is exposed to a number of general risks that could materially affect its financial position, assets and liabilities, reputation, profits, prospects and share price. These could include:

- fluctuations in economic conditions in Australia and internationally, including fluctuations in economic growth, interest rates, exchange rates, inflation, and employment;
- fluctuations in stock markets, domestically and internationally;
- changes in government policies including fiscal policy, monetary policy, and foreign policy;
- changes in political conditions; and
- natural disasters and catastrophic events.

Cash Flow and Liquidity Risk

Central's ability to meet its debts as and when they are due for payment depends on future performance and cash flow from its operations. These cash flows may be affected by broader economic, financial, competitive, legislative and other factors, many of which are beyond the control of the Board of Directors.

Exploration & Appraisal Risk

By its nature, exploration is a high risk business. Most exploration activity, in particular seismic and drilling, is conducted in joint ventures, thus enabling the joint venture participants to spread that risk, and reward. The risks include, but are not limited to, land access risk, geological risk, drilling operations risk, safety and environmental risks. In addition, as with most businesses, there is also market risk, product pricing risk and foreign exchange risk.

Central's activities are subject to extensive government regulation in areas such as exploration rights, drilling practices, environmental performance and workplace health and safety. Central regularly monitors changes in government regulation.

Oil & Gas Estimates

Reservoir engineering is subjective and can only provide an educated estimate of the extent of oil and gas reserves in place. Estimates are not precise and are based not only on knowledge, but experience, interpretation and accepted industry practice. There are a number of variables that can impact economically recoverable reserves, including changes to government regulations, commodity prices and taxes.

Environmental Risk

Central is subject to laws and regulations to minimise the impact of environmental damage arising from its operations. Non-compliance with these laws and regulations can result in substantial penalties and remediation costs. Any change in the laws or regulation may adversely affect Central's business.

Operating and Insurance Risks

Central's key operating risks include governmental regulatory compliance, changes in operating costs, changes in capital maintenance and replacement costs, plant availability and sub-surface extraction. In addition, Central is exposed to changes in $A commodity prices with respect to crude oil sales which are benchmarked against $US international markets. The majority of Central's revenues, however, are generated by gas sales which effectively mitigates $A commodity price risk through the use of long-term, $A fixed price gas sales agreements with credit worthy customers.

The oil and gas industry is hazardous by nature with many inherent risks including potential well blowouts, spills and leaks, ruptures and pollutants. Central maintains insurance cover for the key risks, however full insurance cover may not be available or may be cost prohibitive and as a result any losses Central sustains may only be partially covered by insurance, if at all.

Presently, Central's key risks relating to capital expenditure stem from its ongoing appraisal drilling campaign and its surface facility projects at Mereenie and Palm Valley.

Competition and Human Resource Risk

Central competes with numerous other oil and gas producers that have substantially greater financial resources, staff and facilities. The ability to secure transportation of its product remains a key factor in its competitiveness within the industry.

Central's credentials as an oil and gas explorer and producer are reliant on its ability to attract talented staff and professional service contractors, competing with other larger organisations. Any growth in demand for skilled employees and professional service contractors may adversely impact Central's ability to attract and retain these people.

Health, Safety and Security Risks

The oil and gas industry by its nature has many inherent health and safety risks. Central maintains a strong focus on the health and safety of all those involved or affected by its operations, however the risk of personal injury is always present.

In addition to personal harm, a serious incident may result in reputational damage, the ability to attract and retain employees as well as compensation, regulatory fines and penalties.

Pipeline Tariff Risk

Central will be selling gas into the east coast market following commencement of the Northern Gas Pipeline ("NGP") scheduled for late 2018. The east coast gas market is currently undergoing a restructuring of supply and demand following the commencement of three LNG projects in Queensland. This has placed significant upward pressure on delivered gas prices to the east coast. Central's ex-field gas price for sales into the east coast however, will in part, depend upon pipeline tariffs which are themselves undergoing regulatory review and reform by Federal Government agencies. The outcome of these pipeline reviews and gas market dynamics may be material to Central's ex-field gas pricing received from east coast customers.

Business Strategy

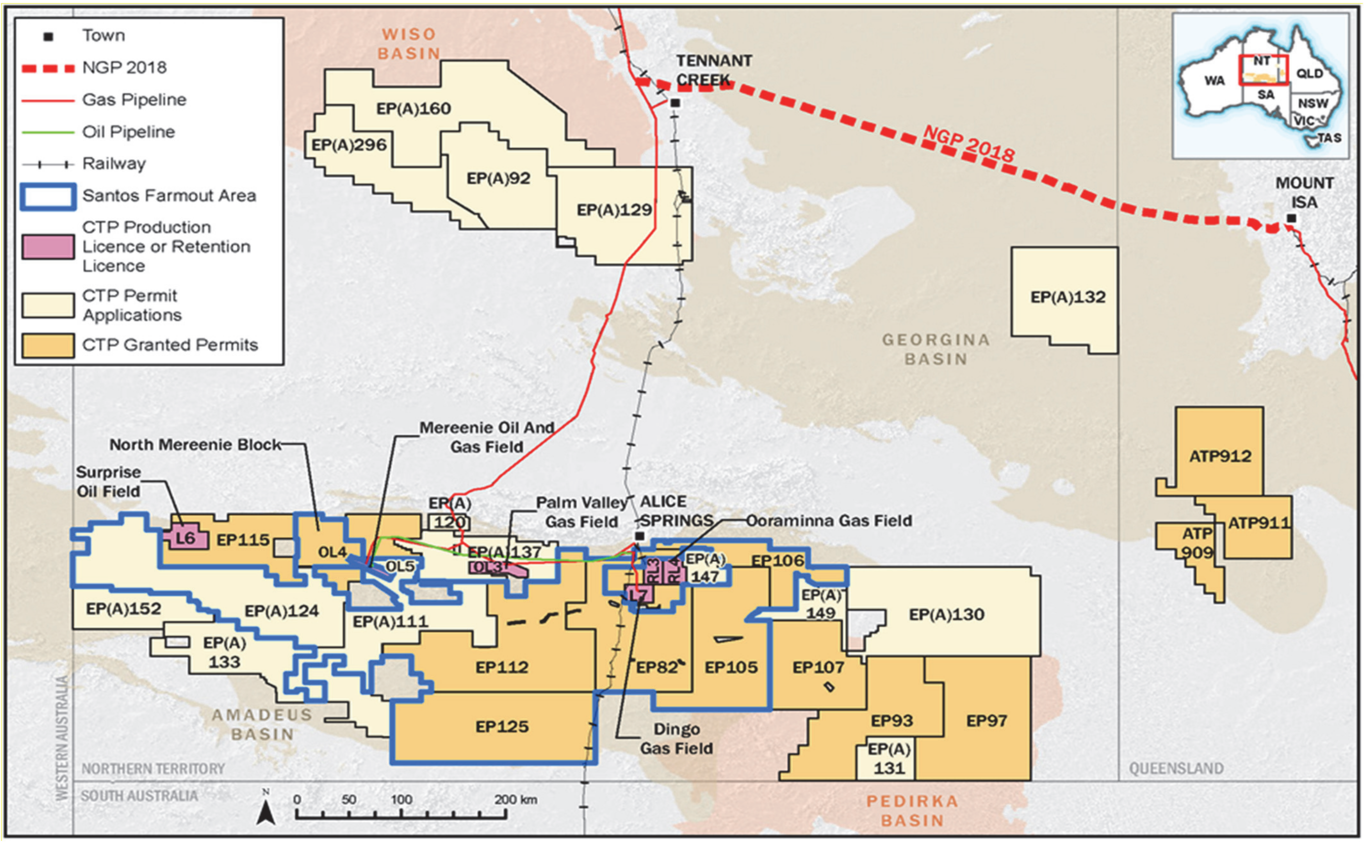
Over the past three years, Central has developed and successfully pursued a strategy to take advantage of a tightening domestic gas market to gain critical mass in conventional gas production and uncontracted gas reserves. This strategy first commenced through the acquisition of the Palm Valley and Dingo gas fields from Magellan in April 2014, marking Central's entry into commercial gas production.

Central's business strategy was bolstered significantly on 1 September 2015 when Central completed the acquisition of 50% of Mereenie from Santos and became Operator for the Joint Venture. The implementation of this business strategy has made Central a substantial onshore domestic gas producer, with approximately 17.2 TJ/d (6.3 PJ p.a.) equity accounted from sales contracts being delivered at 30 June 2018. Central is currently undertaking an appraisal drilling programme to increase uncontracted 2P reserves. Whilst the results of the first appraisal well (WM 26 at Mereenie) were disappointing, we will be conducting a technical review to evaluate opportunities to enhance productivity from the target zones. The PV 13 appraisal well at Palm Valley spudded during August 2018. Whilst resources associated with appraisal wells are brownfield and could be available for delivery into the east coast market from late 2018 via the NGP, completion of certification of the reserves will take longer and occur over time. Both the Mereenie and Palm Valley fields are undergoing substantial surface facility upgrade projects designed to maximise sales capacity and accelerate delivery of existing 2P reserves.

With the Mereenie, Palm Valley and Dingo fields under our common operatorship, Central is now in a unique position to utilise (and actively support) the NGP, which will connect the Northern Territory to the eastern seaboard in late 2018. This project is driven by clear fundamentals of a domestic gas shortfall on the east coast and underexplored onshore gas potential in the Northern Territory. In linking supply and demand, Central's business strategy of acquiring gas assets and uncontracted reserves in advance of the NGP pipeline positioned it to be a direct beneficiary.

The acquisition of Palm Valley, Dingo, and Mereenie were based on existing long-term gas contracts which incorporate fixed prices with CPI escalation. More recent GSAs have also been structured on a similar fixed price basis. This provides a solid revenue stream going forward to cover Central's operating activities. In addition, debt financing arrangements are secured via these long term gas contracts with pricing not affected by oil price or currency movements and are therefore largely unaffected by volatility in international oil or LNG markets. Any future reserve additions and gas sales agreements are expected to result in value accretion to those assets.

Accessing new and higher-value markets for our gas could re-rate our significant under-explored permits throughout the Amadeus, Southern Georgina, Pedirka and Wiso basins in Central Australia. Going forward, our operations are expected to be cash flow positive after debt service which allows us to focus capital on value accretive exploration and appraisal activities.



Granted Petroleum Permits, Licences and Application Interests

Operations and Activities

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2017/18	FY 2016/17
Gas	TJ	4,842	3,224
Crude and Condensate	bbls	105,619	111,380

PRODUCING ASSETS

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory
(CTP—50% Interest [Operator], Macquarie Mereenie Pty Ltd—50% Interest)

The Mereenie oil and gas field was discovered in 1963 and commenced production in 1984, delivering hydrocarbon liquids for sale in South Australia and gas to Northern Territory markets. With the upcoming commissioning of the Northern Gas Pipeline, Mereenie gas will be able to access the east coast gas markets.

The Mereenie hydrocarbon accumulation is contained in an elongated 4-way dip anticline that has a length of 40 km and width of more than 5 km. Reservoirs comprise a series of thin stacked sandstones of the Pacoota Formation which have been the development focus, and in the overlying Stairway Sandstone which has produced gas in several wells where it has been tested. The gas accumulation also has an oil rim.

The key development project underway is the Mereenie Expansion Project to increase the capacity of the facilities to deliver 44 TJ/d of sales gas. The project scope includes installation of additional inlet separation, installation of a new Field Boost Compressor ("FBC"), restaging of the existing FBCs and refurbishment of the 'Plant 3' liquids recovery plant. Front End Engineering Design ("FEED") has been completed and a Final Investment Decision ("FID") was taken during the year to deliver the project in order to satisfy the IPL contract.

An appraisal well, West Mereenie 26, was drilled as a sub-horizontal well in the Stairway Sandstone. The well was designed to intersect an area with a high density of natural fractures. The well was spud on 22 May 2018. Subsequent logging indicated the well did intersect significant fractures, but the fractures were plugged by mineralisation that had occurred during geologic time. In its current configuration, the well was unable to flow at commercial rates and was suspended on 6 July 2018 to enable the Company to potentially explore avenues to enhance well productivity. Further development of the Stairway Sandstone remains under consideration via workovers of existing wells and/or potential further drilling in the future.

Mereenie Eastern Satellite Station Processing Facilities

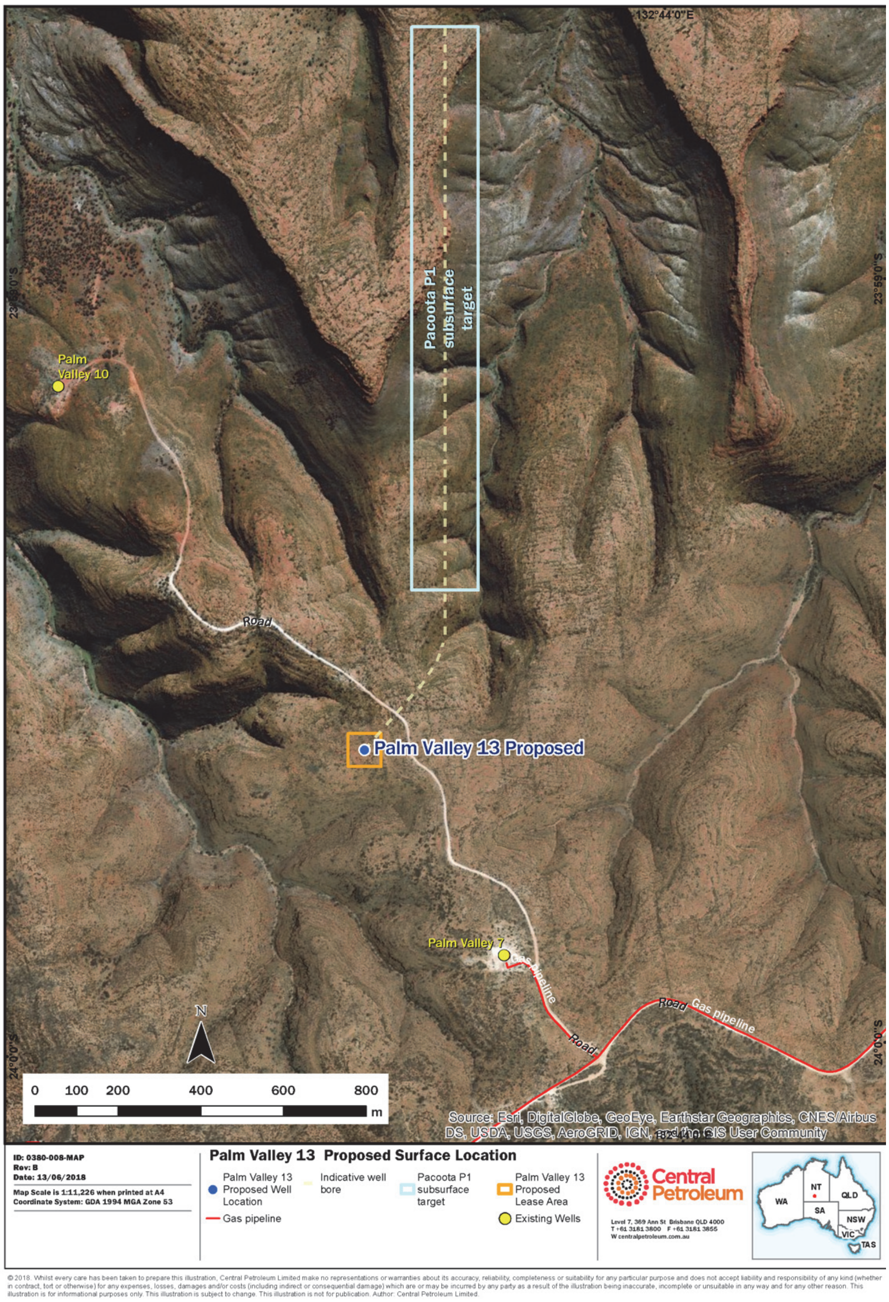
Palm Valley Gas Field (OL3)

Northern Territory
(CTP—100% Interest)

Gas was first discovered at Palm Valley in 1965 and is primarily reservoired in an extensive fracture system in the lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone at depths from 1,800 to 2,200 metres. The anticlinal structure is approximately 29 km in length and 14 km in width.

In recent years, the field has been shut-in due to market limitations in the Northern Territory. The key development project underway is the optimisation and restart of the field to deliver 15 TJ/d of sales gas into the broader gas market available via the NGP connection. The early phases of this project determined that the current plant configuration is optimal and onsite activities are now underway to refurbish and reinstate equipment to enable the field to be online prior to the commencement of the IPL contract.

Lease preparation is underway to drill an appraisal well, Palm Valley-13, to evaluate the Stairway, Pacoota Sandstone and Horn Valley Siltstone reservoirs to connect as many as possible of the naturally occurring fractures. It is planned to drill the well as a high angle directional well due to surface constraints. A well design and directional plan has been created that allows for a vertical surface hole to +/-1,000 m followed by a directional build section to intersect the top of the reservoir. This section will be cased with a 7-inch liner. A 6-inch production hole will be drilled horizontally within the Pacoota using direct circulation air/mist drilling techniques. The well spudded in August 2018.



Palm Valley-13 surface location and reservoir trajectory projection

Dingo Gas Field (L7) and Dingo Pipeline (PL30)

Northern Territory
(CTP—100% Interest)

Gas was discovered at the Dingo field in 1985 in the Neoproterozoic lower Arumbera Sandstone. The structure is 11 km by 5.6 km, and the productive reservoir is at a depth of approximately 3,000 metres subsurface.

The Dingo Gas Field Development, completed in April 2015, comprised the construction of wellhead facilities, gathering pipelines, gas conditioning facilities, a 50 km gas pipeline to Brewer Estate in Alice Springs and custody transfer metering facilities. It was designed to service a gas sale contract with Territory Generation.

Central conducted a review of geological and engineering data, and identified upside potential in the field. Several structural leads were identified in the area immediately surrounding Dingo gas field, within Exploration Permit (EP) 82. These could provide interesting incremental opportunities to Central's 100% Dingo infrastructure. Further seismic is required to progress the targets to drillable status.

The field continued to supply the Owen Springs Power Station during the year. Progress continued on two minor projects to install a water bath heater and a TEG unit to improve consistency of gas supply.

Surprise Oil Field (L6)

Northern Territory
(CTP—100% Interest)

Surprise West remained shut-in during the year. The well has been temporarily shut-in to gather pressure data to assess the re-charge potential of the field. The fluid level is being monitored regularly. Further assessment of the pressure build-up, expected well deliverability and production forecast will aid in determining the commerciality of bringing the well back on production.

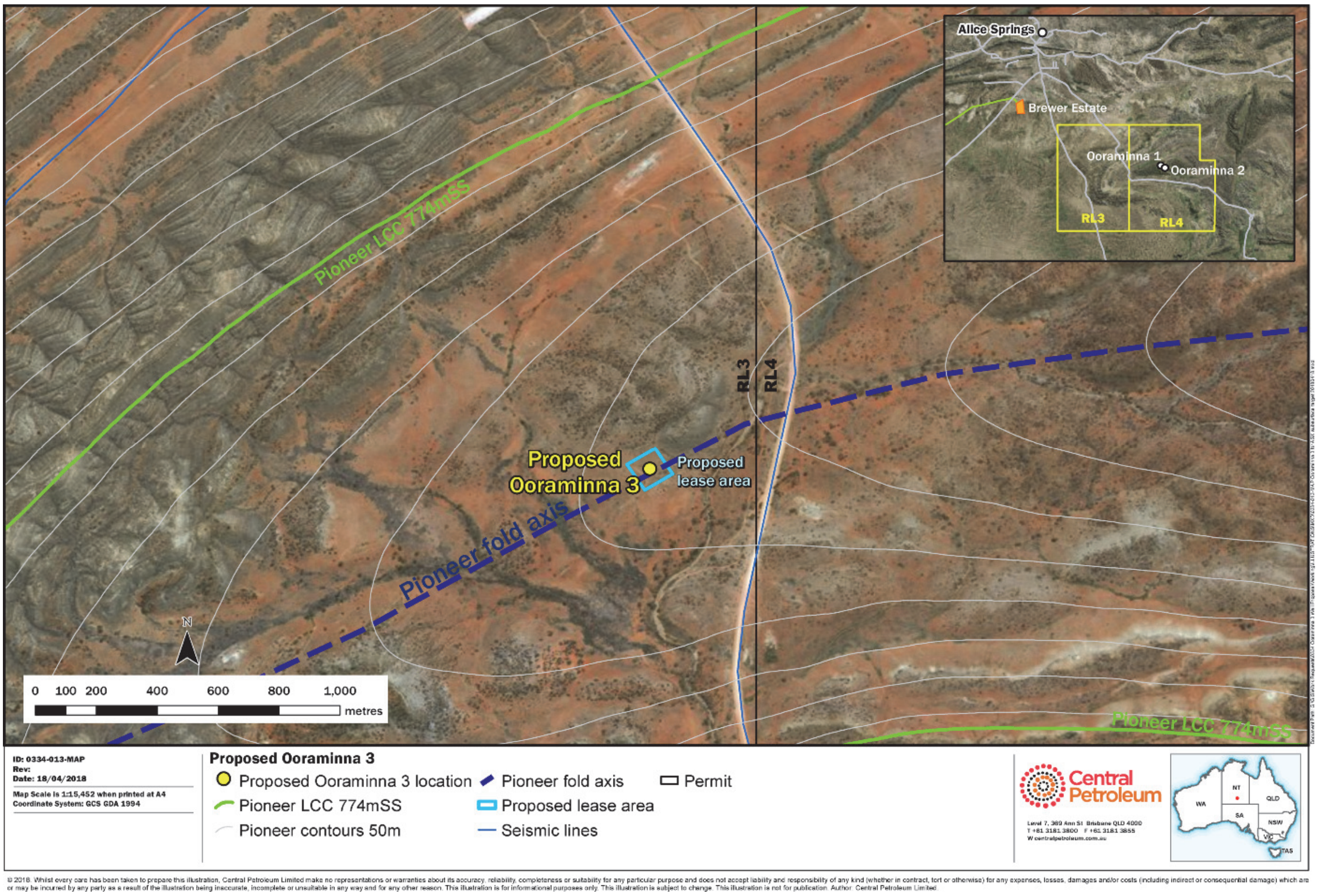
EXPLORATION ASSETS

Ooraminna Field (RL3 and RL4)

Two wells have been drilled at Ooraminna with both wells having proved gas flow from the Pioneer Formation. Although the flow rates were sub-economic, it is encouraging to note that the wells were drilled in an area with apparent low natural fracture density within the Pioneer Formation. Structural mapping has been updated following the reprocessing of the seismic data. This has been augmented by outcrop mapping to assist in structural definition between seismic lines. This updated mapping has been incorporated into a natural fracture model which has defined areas with the greatest fracture density. The subsurface target and well trajectory have now been defined and the surface location of the Ooraminna 3 has also been identified. The Ooraminna field has an inferred closure area of approximately 175 km^2 and preliminary estimates of Original Gas In Place ("OGIP") for the Pioneer Formation range from approximately 125 Bcf to 425 Bcf. Currently, there are no resources certified at Ooraminna, however demonstrating increased productivity through drilling in areas of predicted increased natural fracture density may lead to resource/reserves certification.

Tenure Update

Notices of Intent ("NOI") to Grant for both retention licences were received from the Northern Territory Department of Primary Industry and Resources ("DPIR") on 1 August 2018. The Ooraminna 3 vertical appraisal well is being planned as part of the licence commitments. The well design is to drill 12 ¼ inch top hole and set 9 5/8 inch surface casing at 400m–500m and then an 8 ½ inch hole will be drilled to total depth to allow for a full reservoir evaluation and depth control. Once the data has been analysed a decision will be made as to further drilling or completion options. The well is located to intersect the naturally occurring fractures to enhance the likelihood of the well's success.



Ooraminna 3 surface location and reservoir trajectory projection.

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(CTP—100% interest)

The Department of Natural Resources and Mines ("DNRM") has reviewed the Project Status submission from Central Petroleum. Central will consult with DNRM in Q3, 2018 with regards to the best approach to secure Project Status for the Southern Georgina permits. Central has also finalised lease arrangements for the Boulia warehouse and the consolidation of leases on which this facility sits.

Southern Amadeus Basin

Northern Territory
Various Exploration Permits (see table on page 92)

Santos Stage 2 Farm out – Southern Amadeus Basin, Northern Territory

In April 2018, Santos completed acquisition of 403 km of seismic data, infilling the previous 932 km of seismic acquired in 2016 and bringing the total to 1,335 km, meeting the requirements of the Stage 2 Farm-in with Central. The additional seismic lines reduce dip line spacing over the Dukas prospect to approximately 5 km between dip lines over the central prospect area, and approximately 10 km towards the flanks. Processing of the acquired seismic data has commenced and is progressing.

In addition to seismic data coverage, Santos has also undertaken multi 1D modelling and gravity inversion studies over the Southern Amadeus to further understand the structural history, magnitude of missing section and the implications on present-day structure. The structural model continues to be refined with the addition of these new learnings.

The joint venture's exploration endeavours on these permits focus on maturing large sub-salt leads. The primary reservoir objective is the Heavitree Quartzite. Secondary reservoir objectives in the Neoproterozoic post-salt units include the Areyonga Formation and Pioneer Sandstone, which are gas bearings in the Dingo and Ooraminna fields, respectively.

Central continues to monitor data in these permits, seeking to upgrade a variety of exploration play types and targets, which could be prospective for hydrocarbons and/or helium.

Looking forward, Santos has requested a further 3-month extension of the Stage 2 end date to 3 October, 2018. Santos has also requested an additional five month extension on the Stage 3 end date to 3 November 2019. Central is currently considering these requests.

Southern Amadeus Area	Total Santos Participating Interest after completion of Stage 1	Total Santos Participating Interest after completion of Stage 2
EP 82 (excluding EP 82 Sub-Blocks)	25%	40%
EP 105	25%	40%
EP 106 *	25%	40%
EP 112	25%	40%
EP 125	70%	70%

* *Santos (as Operator) has continued the process of an application with the NT Department of Primary Industry and Resources for consent to surrender Exploration Permit 106.*

Amadeus Basin (includes EP115 North Mereenie Block), Northern Territory

Central's evaluation of inventory of leads and prospects is now completed. Play types and leads have been developed for the under-explored section underlying the proven Larapintine system, which is believed to be prospective for gas.

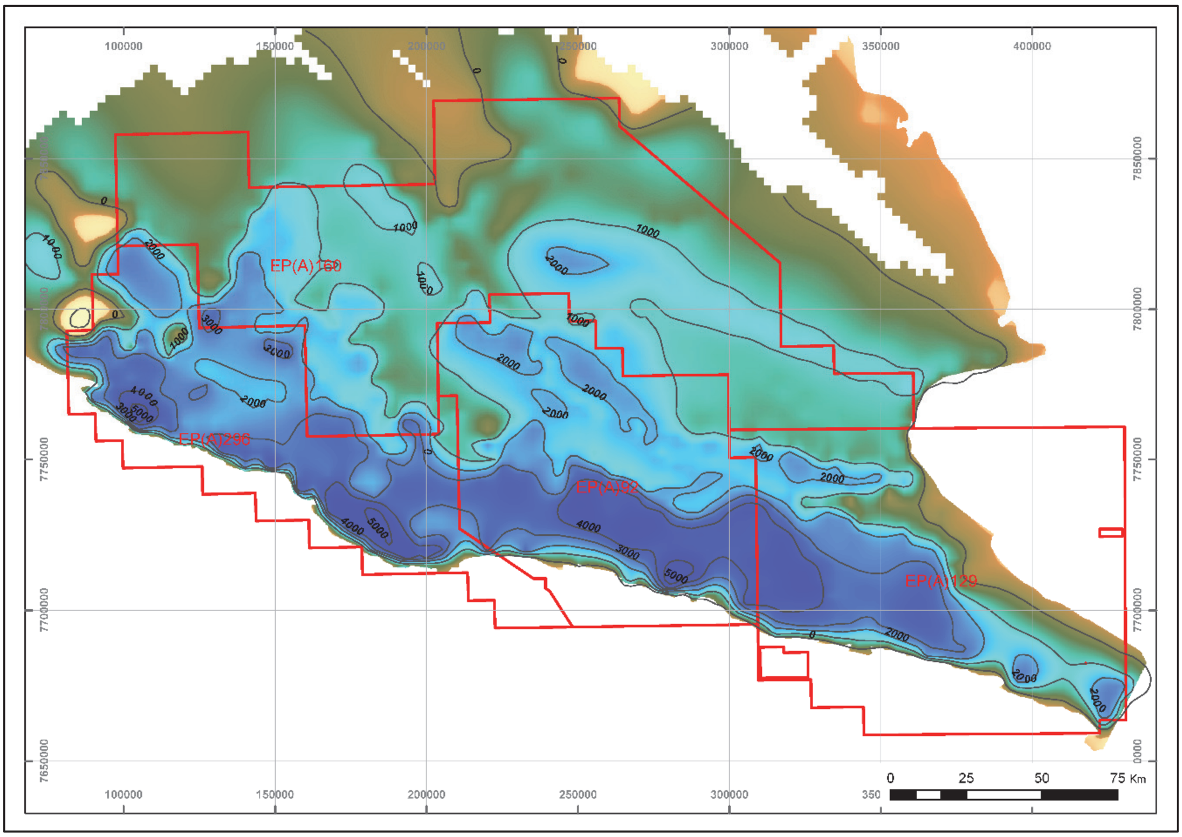
Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 92)

The Company continued to evaluate a number of these areas and has been working to gain Native Title/ALRA clearance and secure the other necessary approvals in advance of award of exploration permit status.

Across the Amadeus Basin, further review of the seismic, well, magnetic and recently acquired gravity data was completed resulting in an inventory of leads and prospects. Play types and leads are also being developed for the under explored section underlying the proven Ordovician Larapintine system which is believed to be prospective for gas. In the western Amadeus a preliminary seismic programme that targets identified structural trends and leads with the aim of defining areas for follow up infill seismic has been designed.

In the Wiso Basin, a gravity survey was conducted by Geoscience Australia and Northern Territory Geologic Survey in 2013, which has provided Central with improved detail of structural trends. Interpretation and forward modelling in conjunction with magnetic, borehole and outcrop data has led to the generation of a depth to basement map, from this a proposed seismic grid has been created.



Wiso Basin depth to basement and application areas

Reserves Information

Net proved ("1P") gas reserves were 81.03 PJ and net proved ("1P") oil reserves were 0.37 MMbbl at 30 June 2018. 1P gas reserves decreased by 3.63 PJ while 1P oil reserves decreased 0.09 MMbbl, both through continued production.

Net proved plus probable ("2P") gas reserves were 122.9 PJ and net proved plus probable ("2P") oil reserves were 0.38 MMbbl at 30 June 2018.

All reserves and contingent resources volumes are based on independent expert Netherland, Sewell & Associates Inc ("NSAI"), reviewed and reported volumes for the respective Petroleum Resources Management System compliant categories, dated 30 June 2015 for Palm Valley and Dingo and 31 December 2015 for Mereenie oil and gas.

AGGREGATE RESERVES (Central Petroleum Share)

	Unit	30/06/2018	Production for the period 01/07/2017 - 30/06/2018	01/07/2017
Oil				
Proved reserves	MMbbl	0.37	0.09	0.45
Proved plus probable reserves	MMbbl	0.38	0.09	0.47
Contingent Resources 2C	MMbbl	0.10	-	0.10
Gas				
Proved reserves	PJ	81.03	3.63	84.66
Proved plus probable reserves	PJ	122.90	3.63	126.53
Contingent Resources 2C	PJ	143.60	-	143.60

RESERVES PER ENTITY (Central Petroleum Share)

	Unit	30/06/2018	Production for the period 01/07/2017 - 30/06/2018	30/06/2017
Mereenie, oil				
Proved reserves	MMbbl	0.37	0.09	0.45
Proved plus probable reserves	MMbbl	0.38	0.09	0.47
Contingent Resources 2C	MMbbl	0.10	-	0.10
Mereenie, gas				
Proved reserves	PJ	56.23	2.83	59.06
Proved plus probable reserves	PJ	69.30	2.83	72.14
Contingent Resources 2C	PJ	91.20	-	91.20
Palm Valley				
Proved reserves	PJ	16.69	0.01	16.70
Proved plus probable reserves	PJ	22.59	0.01	22.60
Contingent Resources 2C	PJ	29.70	-	29.70
Dingo				
Proved reserves	PJ	8.11	0.79	8.89
Proved plus probable reserves	PJ	31.01	0.79	31.79
Contingent Resources 2C	PJ	22.7	-	22.7

Note: Estimates may not arithmetically balance due to rounding

QUALIFIED PETROLEUM RESERVES AND RESOURCES EVALUATOR STATEMENT

The information contained in this report regarding the Central Petroleum reserves, contingent resources is based on, and fairly represents, information and supporting documentation reviewed by Mr Richard Hamilton who is a full-time employee of Central Petroleum holding the position of Subsurface Development Manager. Mr Hamilton holds a Master of Science degree, is a member of the Society of Petroleum Engineers, is qualified in accordance with ASX listing rule 5.41, and has consented to the inclusion of this information in the form and context in which it appears.

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

The financial position and performance of the group was particularly affected by the following events and transactions during the year ended 30 June 2018:

- The Company made a fully underwritten institutional and sophisticated investor placement of 92,000,980 shares at an issue price of $0.10 per share. In addition, the Company undertook a 5 for 12 traditional non-renounceable entitlement offer, issuing a further 180,499,020 shares also at $0.10 per share. These raised gross contributions of $27,250,000 before costs of $1,775,044.
- The results and cash flows include revenue from the supply of gas under a GSA with EDL, which commenced in June 2017.

In addition to the above events that impacted the financial results for the year ended 30 June 2018, there were other events that will have a forward impact on the state of affairs of the group.

The group entered into a new GSA with IPL during the year. Central will deliver at least 20 TJ/day of gas to IPL on an ex-field basis from its Palm Valley and Mereenie fields. The gas will be delivered from the commencement of commercial operations of the NGP until 31 December 2019.

Additionally, a 50:50 joint venture arrangement for ATP 2031 in Queensland will be established with IPL, allowing the fast tracking of developing this acreage. IPL will contribute up to $20 million for appraisal drilling costs during the initial exploration period with drilling anticipated for 2019.

EVENTS SINCE THE END OF THE FINANCIAL YEAR

In July 2018, it was announced that Mr Richard Cottee will cease employment on 31 January 2019. Mr Leon Devaney is acting CEO in the interim period.

In July 2018, the Consolidated Entity submitted objections in respect of its income tax assessments for the income years ended 30 June 2013 to 30 June 2016 inclusive. The objections relate to Research & Development Tax offsets and the treatment of Farmout Arrangements in respect of those years of income. As at 30 June 2018 the Consolidated Entity has not recognised any potential tax benefits from the objections lodged.

In August 2018, Central was formally awarded ATP 2031 by the Queensland government.

GRR's appeal opposing jurisdiction in the Supreme Court of Queensland was dismissed in the Company's favour on 14 September 2018 (refer to Note 29 (a) (iii) for further details).

On 26 September 2018, the Consolidated Entity's debt facility with Macquarie Bank was extended by a further $7.5 million. Drawdowns under this extension are at Central's election and will be repayable in equal instalments from April to December 2019. As part of the arrangement the Company will grant Macquarie Bank up to 22.5 million options with an exercise price of 14 cents and expiring December 2019. Options will be granted in four equal tranches, the first on completion of the agreement and the remaining tranches as funds drawn down under the facility reach certain thresholds.

On 27 September 2018, Central Petroleum Limited secured a $10 million facility with Hong Kong based investment company Long State Investment Limited ("LSI"). Under the terms of the facility, Central Petroleum Limited may, at its discretion, issue shares to LSI at any time over the next 24 months, up to a total of $10 million. Central Petroleum Limited may draw down up to $250,000 in any period of 5 trading days.

Shares issued to LSI will be priced at the lowest daily volume weighted average price ("VWAP") of Central Petroleum Limited shares traded on each of the 5 trading days which follow an advance notice by Central Petroleum Limited. A commission of 5% will be payable by Central Petroleum Limited at the time of issue.

LSI may receive up to five million unlisted options through four separate tranches that are subject to ELOC utilisation. An initial tranche of 1.25 million options with an exercise price of 35 cents will be granted on activation of the ELOC. Further tranches of 1.25 million options, with an exercise price of 200% of the 20 day VWAP immediately preceding the date on which Central is required to grant the options, will be granted when the aggregate advances first exceeds $2.5 million, $5.0 million, and $7.5 million. The options have an exercise period of five years from the date of issue. To date, Central has not utilised the ELOC and no options have been granted.

No other matter or circumstance has arisen that will affect the Group's operations, results or state of affairs, or may do so in future years.

DIRECTORS' REPORT

FOR THE YEAR ENDED 30 JUNE 2018

INFORMATION ON DIRECTORS

Martin Kriewaldt, BA, LL.B (Hons 1st), University Medal, FAICD (Life), AICDQ Gold Medal

Independent Non-executive Chairman

Mr Kriewaldt was appointed a Director on 23 October 2017 and is a professional company Director with over 25 years' experience.

He is a Life Fellow of the Australian Institute of Company Directors, serves on its Corporate Governance Committee, is Chair of an AICD Nexus group and a Mentor in the AICD mentoring programme for women. He is a past President of the Institute of Company Directors (Queensland Division) and has been awarded the AICD Gold Medal.

He was previously Chairman of Suncorp, Infratil Australia, Suncorp Property Trust and Thin Technologies, and was a Director of listed entities including Campbell Brothers, Oil Search, Macarthur Coal, GWA, ImpediMed, BrisConnections and QDL. He has also been the Chairman or a Director of a number of unlisted companies including Suncorp Building Society, Suncorp Finance, Hooker Corporation, Graham and Company and Golding Contractors, as well as the national board of AICD.

In addition to these roles, he has chaired Board Sub-Committees for Audit, Risk, Environment, Remuneration, Investment, Corporate Governance, Corporate Advisory and Nominations. He has also served as Deputy Chairman and Lead Independent Director. He was Chairman of Opera Queensland and has also served on a number of other not-for-profit boards, including the Senate of the University of Queensland.

Previously, Mr Kriewaldt was a Partner of Allen Allen & Hemsley (now Allens Linklaters) for 25 years specialising in banking and insurance, mining, oil and gas and construction.

Richard Cottee BA, LLB (Hons)

Managing Director and Chief Executive Officer

Mr Cottee is a veteran of the oil and gas industry having started his commercial career with Santos Ltd in 1982. He was instrumental in the development of the CSG industry having taken QGC from an early stage explorer, with a market capitalisation of approximately $30 million, to a major gas supplier, which was sold to the BG Group for $5.7 billion six years later. He has extensive experience in the energy sector generally, having been a CEO of a Queensland electricity generator (CS Energy) and of a subsidiary of NRG in Europe. In his career he has had a role in the development of the industry in Queensland, South Australia and now the Northern Territory.

Mr Cottee joined Central Petroleum Limited in June 2012 as Managing Director and within the last three years has not been a Director of any listed public company other than Austin Exploration Limited where he was a non-executive chairman until April 2015.

Wrixon F Gasteen BE (Mining) (Hons), QLD, MBA (Distinction), Geneva

Independent Non-executive Director

Mr Gasteen is a Director and co-founder of Ikon Corporate (Singapore), established in 2007 to provide corporate advisory, capital raising and management consulting services. He has over 20 years' experience in the mining, oil and gas, manufacturing and IT industries in Australia and Asia.

Mr Gasteen has been CEO and Director of both listed and private companies in Australia, Asia, and the United States, and is a senior advisor to Australian companies.

He has held senior management positions in the Resources Industry in Australia. As Chief Mining Engineer, he led the technical team that discovered and then developed the Boundary Hill Coal Mine in Central Queensland. He became its inaugural Mine Manager.

As CEO and Director of Hong Leong Asia Limited, listed on the Singapore Stock Exchange (SGX: HLA), he transformed the company through acquisitions and organic growth from a loss making company with revenue of $300 million to a highly profitable conglomerate with $2.2 billion in sales, 80% of which were in China and the remainder in SE Asia. During his term as CEO, he was presented with two successive annual awards by the Securities Investors Association of Singapore, recognising Hong Leong Asia for its effort in demonstrating corporate transparency. The BRW ranked Mr Gasteen No.3 in their Top 20 Australians Managing in Asia.

Mr Gasteen was also Director of Tasek Corporation (cement) listed on Kuala Lumpur Stock Exchange and Chairman and President of China Yuchai International (diesel engines) listed on the New York Stock Exchange. He was appointed Non-Executive Director and Chairman of the Audit Committee of ASX listed, Sino Australia Oil and Gas in March 2014, resigning in November 2015.

Dr Peter S Moore BSc (Hons 1), MBA, PhD, GAICD

Independent Non-executive Director

Dr Moore has more than thirty five years' experience in the oil and gas business. His career includes roles with the Geological Survey of Western Australia, Delhi Petroleum Pty Ltd, the exploration operator of the Cooper Basin consortium in South Australia and Queensland at the time, Esso Australia Ltd, Exxon Exploration Company (Houston), Woodside Energy Ltd and Curtin University.

At Woodside, Peter held various roles including most recently as Executive Vice President Exploration. In this capacity he was a member of Woodside's Executive Committee and Opportunities Management Committee, a leader of its Crisis Management Team and Head of the Geoscience function across the company. He was also a Director of a number of Woodside's subsidiary companies.

Dr Moore is a Non-executive Director of Carnarvon Petroleum Limited and Beach Energy Limited. Until 31 March 2018, he was Professor and Executive Director, Corporate Engagement at Curtin Business School. Dr Moore is Chair of ESWA Inc and a member of Curtin University's Faculty of Science and Engineering Advisory Council. Within the last three years, Dr Moore has not been a Director of any other listed public company.

Sarah Ryan, PhD (Petroleum and Geophysics), BSc (Geophysics) (Hons 1), BSc (Geology)

Independent Non-executive Director

Dr Sarah Ryan was appointed a Director to the Central Board on 23 October 2017 and is a professional company Director and seasoned professional with over 25 years' local and international experience primarily in the oil and gas industry.

Dr Ryan currently holds non-executive directorships with Woodside Petroleum Ltd, MPC Kinetic Group, Akastor ASA (Oslo, Norway) and Viva Energy. Previous positions include non-executive Director of Aker Solutions ASA (Oslo, Norway), Advisor-Energy to Earnest Partners (Atlanta, USA) and Advisor to the Chairman of Saxo Bank A/S (Copenhagen, Denmark). She is also Chair of the Advisory Board of Unearthed Solutions.

During her career, Dr Ryan was Investment Director and Portfolio Manager at Earnest Partners, an Atlanta based investment management firm, Chief Operating Officer of MTEM Ltd (Edinburgh, UK), General Manager of Asset Management for AGL (Sydney, Australia) and held various technical, operational and executive positions with Schlumberger, both in Australia and overseas, during a 15 year tenure.

Dr Ryan holds a PhD in Petroleum Geology and Geophysics, a BSc (First Class Honours) in Geophysics, and a BSc in Geology. In addition, she is a Fellow of the Australian Academy of Technology and Engineering, Fellow of the Institute of Energy, Member of the Australian Institute of Company Directors, Member of Women Corporate Directors, and Member of Chief Executive Women.

Tim Woodall, BEcon, FCPA, GAICD

Independent Non-executive Director

Mr Woodall was appointed a Director to the Central Board on 20 December 2017 and has over 25 years' experience in international M&A and finance, specialising in the oil and gas sector.

His expertise includes being the founder and Managing Director of a boutique advisory firm, the CEO of a technical consulting firm and senior roles in New York and London with global investment banks. Additionally, he has held senior executive positions with E&P companies in Australia and the USA.

Mr Woodall has a Bachelor of Economics from the University of Adelaide, is a Fellow of the Australian Society of CPAs (FCPA) and a graduate member of the Australian Institute of Company Directors (GAICD).

Mr Woodall is currently a Non-executive Director of FAR Limited.

COMPANY SECRETARIES

Daniel C M White LLB, BCom, LLM

Mr White is an experienced oil and gas lawyer in corporate finance transactions, mergers and acquisitions, equity and debt capital raisings, joint venture, farmout and partnering arrangements and dispute resolution. He has previously held senior international based positions with Kuwait Energy Company and Clough Limited.

Joseph P Morfea FAIM, GAICD

Mr Morfea has over 35 years of experience in the resource industry having held key financial positions with both Australian and international based companies. He was previously the chief financial officer of Magellan Petroleum Australia Pty Ltd, a wholly owned subsidiary of Denver based Magellan Petroleum Corporation and has also held board and advisory committee positions. Prior to Magellan, Mr Morfea worked for Santos Limited and Thiess Dampier Mitsui Coal Pty Ltd.

DIRECTORS' MEETINGS

The numbers of meetings of the company's board of directors and of each board committee held during the financial year, and the numbers of meetings attended by each Director were:

Director	Full Meeting of Directors		Audit & Risk Committee		Remuneration & Nominations Committee	
	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Robert Hubbard[3]	11	7	2	1	2	2
Richard Cottee	16	14	—	3	—	—
Wrixon Gasteen	16	16	4	4	4	4
Martin Kriewaldt[4]	9	9	1	3	—	1
Peter Moore	16	16	2	2	4	4
Sarah Ryan[4]	9	9	1	3	2	2
Timothy Woodall[5]	8	7	2	1	—	—

[1] *Number of meetings held during the time the director held office or was a member of the committee during the year*
[2] *The number of meetings attended includes those attended by invitation*
[3] *Robert Hubbard retired 14 May 2018*
[4] *Martin Kriewaldt and Sarah Ryan were appointed Directors on 23 October 2017*
[5] *Timothy Woodall was appointed Director on 20 December 2017*

REALISED REMUNERATION OF DIRECTORS AND KEY MANAGEMENT PERSONNEL FOR THE 2018 YEAR

The Directors consider the remuneration information contained within the tables presented in the statutory remuneration report (pages 23 to 32) may give a distorted view of the true remuneration realised by the directors and key management personnel for the 2018 year.

This is a voluntary disclosure and has been included to assist shareholders in forming an understanding of the cash and other benefits actually received by Directors and key management personnel.

Non-Executive Directors	Salary / fees $	STIP $	Non-monetary benefits[1] $	Termination benefits $	Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Wrixon Gasteen	93,333	—	912	—	8,867	103,112	100%	—	103,112
Robert Hubbard[2]	104,710	—	—	—	9,947	114,657	100%	—	114,657
Martin Kriewaldt[3]	59,362	—	—	—	5,639	65,001	100%	—	65,001
Peter Moore	83,333	—	—	—	7,917	91,250	100%	—	91,250
Sarah Ryan[3]	52,670	—	—	—	5,004	57,674	100%	—	57,674
Timothy Woodall[4]	38,889	—	—	—	3,694	42,583	100%	—	42,583
Sub-total	432,297	—	912	—	41,068	474,277	100%	—	474,277

Executive Directors & Key Management Personnel	Salary / fees $	STIP $	Non-monetary benefits[1] $	Termination benefits $	Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Richard Cottee	587,491	51,888	16,550	—	20,049	675,978	99%	9,714	685,692
Leon Devaney	499,778	39,346	5,460	—	24,085	568,669	98%	12,547	581,216
Ross Evans[6]	29,167	—	—	—	2,771	31,938	100%	—	31,938
Michael Herrington	501,212	36,103	6,280	—	23,634	567,229	97%	17,952	585,181
Robin Polson[5]	50,000	—	—	—	4,750	54,750	100%	—	54,750
Daniel White	412,561	28,440	5,460	—	23,417	469,878	97%	14,864	484,742
Sub-total	2,080,209	155,777	33,750	—	98,706	2,368,442	98%	55,077	2,423,519
Total Remuneration	**2,512,506**	**155,777**	**34,662**	—	**139,774**	**2,842,719**	**98%**	55,077	**2,897,796**

1 *Fringe benefits include loan fringe benefits relating to deferred Director option fees and employee car parking fringe benefits*
2 *Robert Hubbard retired 14 May 2018*
3 *Martin Kriewaldt and Sarah Ryan were appointed Directors 23 October 2017*
4 *Timothy Woodall was appointed Director 20 December 2017*
5 *Robin Polson commenced 1 May 2018*
6 *Ross Evans commenced 1 June 2018*

ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation.

The Consolidated Entity aims to ensure the appropriate standard of environmental care is achieved and, in doing so, that it is aware of and is in compliance with all environmental legislation. The Directors of the Company and the Consolidated Entity are not aware of any breach of environmental legislation for the year under review.

INSURANCE OF DIRECTORS AND OFFICERS

During the financial year, the Group paid premiums to insure Directors and officers of the Group. The contracts include a prohibition on disclosure of the premium paid and nature of the liabilities covered under the policy.

NUMBER OF EMPLOYEES

The Company had 89 employees at 30 June 2018 (83 at 30 June 2017).

NON-AUDIT SERVICES

During the year the Company engaged the auditor, PricewaterhouseCoopers ("PwC"), on assignments additional to their statutory audit duties where the auditor's expertise and experience with the Company and/or the Consolidated Entity was important.

Details of amounts paid or payable to the auditor (PwC) for non-audit services provided during the year are set out below.

The Board of Directors is satisfied that the provision of the non-audit services is compatible with the general standard of independence for auditors imposed by the *Corporations Act 2001*. The Directors are satisfied that the provision of non-audit services by the auditor, as set out below, did not compromise the auditor independence requirements of the *Corporations Act 2001* and did not compromise the general principles relating to auditor independence in accordance with APES 110 Code of Ethics for Professional Accountants set by the Accounting Professional and Ethical Standards Board.

	CONSOLIDATED	
	2018	2017
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	8,160	17,615
Other tax related services	26,259	19,622
	34,419	**37,237**
(ii) Other services		
Technical accounting advice on major transactions	—	—
Employee related services	—	—
	—	—
Total remuneration for non-audit services	**34,419**	**37,237**

AUDITOR'S INDEPENDENCE

A copy of the Auditor's Independence Declaration as required under section 307C of the *Corporations Act 2001* is set out on page 33.

STAFF AND MANAGEMENT

The Directors wish to acknowledge the contributions made by the Company's staff and management. The skills and dedication of all of Central's personnel both in the field and at Head Office are greatly appreciated and valued.

REMUNERATION REPORT (AUDITED)

This remuneration report for the year ended 30 June 2018 outlines the remuneration arrangements of the Group in accordance with the requirements of the *Corporations Act 2001* (Cth)*, as amended (the Act).* This information has been audited as required by section 308(3C) of the Act.

The remuneration report is presented under the following sections:

A	Directors and Key Management Personnel ("KMP")
B	Remuneration Overview
C	Remuneration Policy
D	Remuneration Consultants
E	Long Term Incentive Plan ("LTIP")
F	Short Term Incentive Plan ("STIP")
G	Remuneration Details
H	Executive Service Agreements
I	Non-Executive Director Fee Arrangements

A. Directors and Key Management Personnel

The Directors and key management personnel of the Consolidated Entity during the year and up to signing date of the annual report were:

Directors

Robert Hubbard	Non-executive Chairman (retired 14 May 2018)
Martin Kriewaldt	Non-executive chairman (appointed 23 October 2017)
Richard Cottee	Managing Director and Chief Executive Officer (to 30 July 2018)
Wrixon Gasteen	Non-executive Director
Peter Moore	Non-executive Director
Sarah Ryan	Non-executive Director (appointed 23 October 2017)
Timothy Woodall	Non-executive Director (appointed 20 December 2017)

Other Key Management Personnel

Leon Devaney	Chief Financial Officer and Acting Chief Executive Officer (from 31 July 2018)
Ross Evans	Chief Operations Officer (commenced 1 June 2018)
Michael Herrington	President - Operations and Chief Development Officer
Robin Polson	Chief Commercial Officer (commenced 1 May 2018)
Daniel White	Group General Counsel and Company Secretary

B. Remuneration Overview

Central's remuneration strategy is designed to attract, motivate and retain high performing individuals and is linked to the Group's objectives to build long-term shareholder value. In doing so, Central adopts a pay for performance culture which is balanced by a fair and equitable approach to the retention and motivation of its team. The remuneration strategy incorporates the following metrics:

a. Measuring Central's achievement of its targets and performance against its peers
b. Peer company comparative indicators such as market capitalisation, size, complexity of operations and market developments
c. Adjusting to remuneration best practice
d. Market movements and its impact on the alignment of internal relativities
e. Linking internal strategies for the achievement of improved shareholder value.

Financial Year 2018, summary of fixed and variable remuneration outcomes	
Inflation Salary average increases of 1.9%	Where appropriate, a pay rise was awarded to address inflation and on account of a change in role, responsibilities or other extenuating circumstances.
STIP	The Company's Short Term Incentive Plan was scheduled and paid during the first quarter of fiscal year 2019.
LTIP Vesting	Awards vested under the Long Term Incentive Plan for the three year period ending 30 June 2017 during fiscal year 2018.

C. Remuneration Policy

The remuneration policy of the Company is to pay its Directors and executives amounts in line with employment market conditions relevant to the oil and gas industry whilst reflecting the specific circumstances of Central. The Company's remuneration practices and, in particular, its short term and long term incentive plans have a particular focus on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, the major component of executive incentives will be the Long Term Incentive Plan ("LTIP") rather than the Short Term Incentive Plan ("STIP").

D. Remuneration Consultants

For each annual remuneration review cycle, the Remuneration Committee considers whether to appoint a remuneration consultant and, if so, their scope of work. In this period the Remuneration Committee appointed Guerdon Associates to undertake certain work. The report provided contained no recommendations as to the elements or amounts of Key Management Personnel remuneration.

The performance of the Company depends upon the quality of its Directors and executives and the Company strives to attract, motivate and retain highly qualified and skilled management. Salaries and Directors' fees are reviewed at least annually to ensure they remain competitive with the market.

For periods up to and ending on 30 June 2018, the remuneration of Directors and executives consisted of the following key elements:

Non-executive Directors:

1. Fees including statutory superannuation; and
2. No further participation in short or long term incentive schemes. Whilst some of the current non-executive Directors benefit from options issued in accordance with shareholder approval in 2012, no further issues have been made and it is not intended that non-executive Directors will participate in either the LTIP or STIP in the future.

Executives, including Executive Directors:

1. Annual salary and non-monetary benefits including statutory superannuation;
2. Participation in a Short Term Incentive Plan;
3. Participation in an Long Term Incentive Plan (Performance Rights scheme); and
4. There is no guaranteed base pay increases included in any executive's contract.

E. Long Term Incentive Plan ("LTIP")

In its 2014 Annual Report, Central announced that from 1 July 2014 it would change its remuneration practices and, in particular, the structure of its STIP and LTIP in line with market conditions relevant to the oil and gas exploration industry.

The LTIP will be a major component of executive incentives and, in developing the LTIP, the Board of Central has focused on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, vesting conditions have been divided equally between relative shareholder return and absolute shareholder return. In doing this the Board have identified that it is not sufficient for Central to perform above its peer group for executives to receive their maximum entitlement to share rights but also to achieve levels of absolute share price growth that would be considered as superior returns. For example, for the absolute share price vesting condition to be met, the Central share price must increase by at least 25% per annum for three years, compound growth of 95%.

Key terms and vesting conditions

On 26 November 2014 and subsequently on 2 November 2015, shareholders approved the Company to implement a share based LTIP to incentivise eligible employees (Non-Executive Directors are not eligible to participate in the LTIP). The delivery instrument is performance rights, effective for years commencing 1 July 2014 onwards.

The maximum number of performance rights vested in any year is determined by measuring Central's share price performance over that year compared to a peer group of companies (relative measure) and compared to its absolute share price movement over a three year cycle.

The following table details the percentage of Share Rights which will vest (Vesting Percentage) as determined by the performance conditions:

HURDLE	DEFINITION	HURDLE BANDING	VESTING PERCENTAGE
Absolute TSR[1] growth **(50% weighting)**	Company's absolute TSR calculated as at vesting date. This looks to align eligible employee's rewards to shareholder superior returns	Company's Absolute TSR over 3 years	Share Rights Vesting
		Below 10% pa	0%
		10% to <15% pa	25%
		15% to <20% pa	50%
		20% to <25% pa	75%
		25% pa plus	100%
Relative TSR – E&P[2] **(50% weighting)**	Company's TSR relative to a specific group of exploration and production companies (determined by the Board within its discretion) calculated as at vesting date.	Company's Relative TSR	Share Rights Vesting
		Below 51st percentile	0%
		51st percentile	50%
		52nd to 75th percentile	51% to 99%
		76th percentile and above	100%

1 *Total shareholder return (i.e. growth in share price plus dividends reinvested)*
2 *Exploration and Production*

For the purposes of determining the maximum number of unvested Share Rights available for vesting, the Company will calculate the Company's absolute TSR (total shareholder return as measured by an independent company chosen by the Board) and relative TSR effective as at the vesting date in accordance with the above table to determine the relative hurdle band and Vesting Percentage met. The unvested Share Rights for the applicable hurdle met for the performance period are then multiplied by the Vesting Percentage achieved for that hurdle to determine the total number of unvested Share Rights vested to become Share Rights on the vesting date, which may then be exercised in accordance with the Employee Rights Plan Rules.

Subject to the vesting of unvested Share Rights on the Vesting Date, the unvested Share Rights vest at the rate of one Share Right for one unvested Share Right.

The personal and corporate key performance indicators and other targets for the Managing Director and other employees are reviewed at least annually to ensure they remain relevant and appropriate. These may be varied to ensure alignment of executive performance and achievement consistent with the Company's goals and objectives.

Employees must be employed by the Company at the end of the Performance Period in order for the Performance Rights to vest. The number of shares that vest is a function of the employee's base salary, their LTIP percentage, and the 20 trading days—daily volume weighted average sale price of company shares sold on the ASX ending on the trading day prior to 30 June.

If the Company is subject to a Change of Control Event, all unvested Share Rights will immediately vest at 100% to become Share Rights, with all and any Performance Criteria being waived immediately.

Details of the LTIP Plan's Key Terms can be viewed on the Company's website at www.centralpetroleum.com.au.

This LTIP provides coverage for various levels of eligible employees which include:

a. The Managing Director who is principally responsible for achievement of Central's strategy may receive a LTIP percentage up to 50%, subject to shareholder approval;
b. The Executive Management Team ("EMT") and eligible employees are those in roles which influence and drive the strategic direction of the Company's business. EMT eligible employees receive a LTIP percentage up to 30%;
c. Eligible employees who are senior managers that are charged with one or more defined functions, departments or outcomes. They are more likely to be involved in a balance of strategic and operational aspects of management. Some decision-making at this level would require approval from the EMT. These eligible employees receive a LTIP percentage up to 20%;
d. Eligible employees who are not part of the EMT and are in roles which are focused on the key drivers of the operational parts of the Company's business. These eligible employees receive a LTIP percentage up to 10%; and
e. All other eligible employees are integral to the success of the Company obtaining its goals and objectives may participate in Central Petroleum $1,000.00 Exempt Plan.

Conditions of the Central Petroleum $1,000.00 Exempt Plan include:

a. Share Rights can only be dealt with the earlier of three years or on termination of employment; and

b. No performance conditions apply.

Rights Vesting during the Financial Year

During the 2018 financial year 50% of Share Rights issued for the Plan Year commencing 1 July 2014 vested. The vesting percentage was determined on the basis of achieving 100% vesting for Relative TSR and 0% vesting for Absolute TSR, giving an average vesting of 50%.

F. Short Term Incentive Plan ("STIP")

From 1 July 2014, a performance based plan comprising a matrix of Corporate, Departmental and Individual Key Performance Indicators ("KPIs") for all eligible employees was implemented. The Company's Board of Directors determine the maximum amount of KPIs achievable in any year (normally expressed as a percentage of base salary). Achieving the maximum is contingent upon all of the KPIs in the matrix being met at the 100% level. The KPIs are reviewed at the beginning of each year and adjusted where necessary to reflect Central's strategic direction. Consistent with the Directors' focus on appreciation in shareholder value as the major form of incentive, STIP payments were limited to a maximum of 10% of base salary in 2017/18.

Key terms and conditions

The 2017/2018 STIP has been holistically designed to recognise and reward individual effort through connecting individual KPIs, departmental KPIs and corporate KPIs. These groups of KPIs are intrinsically linked and start by cascading from the corporate KPIs, to the departmental KPIs and then onto individual KPIs. Individual KPIs drive the success of achieving departmental KPIs, which are in turn aimed at effecting the desired outcome to be reached in the corporate KPIs.

It is the responsibility of the Board to set the strategic direction priorities and objectives of the Company. The existence of this STIP does not amend or take away that responsibility and, as such, the results of the STIP form part of the Board's deliberation in its decision on the bonus recommendation to be awarded.

The Managing Director approves KPI's after consultation with the Board. These KPIs can change having regard to aligning employees with the Company's strategic direction, the practice in the marketplace and any other factors which the Board deems relevant. Neither the Board nor the Company guarantee any payment from the STIP, nor do they guarantee any performance level of the Company in future years. If there is a change as a result of this, employees participating in the STIP will be notified.

	PERCENT ALLOCATION OF STIP	
KPI CATEGORY	Executive	All Other Employees
Corporate KPIs	30%	30%
Safety and Environment KPI's	10%	10%
Departmental KPIs	40%	30%
Individual KPIs	20%	30%

1. **Corporate KPIs** represent an overall 30% of the STIP
2. **Safety and Environment KPIs** represent 10% of the STIP
3. **Departmental KPIs** represent a spread of 40% for executives and 30% for all other employees
4. **Individual KPIs** represent a spread of 20% for executives and 30% for all other employees

The 2017/2018 Plan Year STIP percentage allocation is a maximum of up to 10% of the employee's Base Salary. The maximum is contingent upon all of the KPIs being met at 100% in the STIP. This will form the basis of the recommendation to the Board who will decide the amount. This percentage will be annually reviewed by the Board through the Remuneration and Nominations Committee.

At the Board's discretion, a combination of cash and company securities, or cash or company securities, may be paid as the benefit in the 2017/2018 Plan Year STIP.

Corporate KPIs included:

OBJECTIVE	WEIGHTING	100%	75%	50%
Drilling	25%	Successful completion of 3 wells	Successful completion of 2 wells	Successful completion of 1 well
Approval & funding of facility upgrades & commercial restructuring – targeting increase sales by NGP becoming operational	25%	25TJ p/day	20TJ p/day	15TJ p/day
Budget (original submission approved by the Board, unless amended due to a Board approved change of scope)	25%	0% (of budget)	5% (of budget)	10% (of budget)
Pipeline Tariffs *	25%	$2.00 per GJ below reference	$1.50 per GJ below reference	$0.75 cents per GJ below reference

** Substantial progress towards the introduction of economic regulation having the intended results for the Company.*

Safety and Environment KPIs included:

OBJECTIVE	WEIGHTING	100%	75%	0%
Traditional Owner cultural heritage: No breach	20%	Zero	1 which has been remedied	Defaulted
Safety: No Lost Time Injuries ("LTI")	30%	Zero	1 of less than 2 days	Defaulted
Environment: No breach regarding reportable environmental incidents	30%	Zero	N/A	Defaulted
Alice Springs local and Indigenous employment	20%	Maintain at least 50% local employment and 25% Indigenous employment in Alice Springs		

The departmental KPIs vary from one department to the next, however, all are equally important to achieve in the pursuit of achieving 100% of the corporate KPIs which are re-set annually. Individual KPIs are linked to the departmental KPIs and as such provides significant relevance to the role that the employee is employed for in each department.

Participation in this STIP, or the provision of any company security, does not form part of the participating employee's remuneration for the purposes of determining payments in lieu of notice of termination of employment, severance payments, leave entitlements, or any other compensation payable to a participating employee upon the termination of employment (unless the Board otherwise determines).

Details of the remuneration of the Directors and the key management personnel of Central Petroleum Limited and the Consolidated Entity are set out in the following tables. Details of realised remuneration appear on page 21.

Table 1: Remuneration of Directors and Key Management Personnel

		SHORT-TERM			POST-EMPLOYMENT		LONG-TERM BENEFITS	SHARE-BASED PAYMENTS (At Risk)		
		Salary / fees $	Cash STI[8] $	Non-monetary benefits[1] $	Superannuation contributions $	Termination Benefits $	LSL $	Options & Rights[9] $	Total $	Value of Options& Rights as Proportion of Remuneration %
Non-Executive Directors										
Wrixon Gasteen	2018	93,333	—	912	8,867	—	—	–	103,112	0%
	2017	75,000	—	15,510	7,125	—	—	9,451	107,086	9%
Robert Hubbard[2]	2018	104,710	—	—	9,947	—	—	—	114,657	0%
	2017	110,000	—	—	10,450	—	—	—	120,450	0%
Martin Kriewaldt[3]	2018	59,362	—	—	5,639	—	—	—	65,001	0%
	2017	—	—	—	—	—	—	—	—	—
Peter Moore	2018	83,333	—	—	7,917	—	—	—	91,250	0%
	2017	80,000	—	—	7,600	—	—	—	87,600	0%
Sarah Ryan[3]	2018	52,670	—	—	5,004	—	—	—	57,674	0%
	2017	—	—	—	—	—	—	—	—	—
J Thomas Wilson[4]	2018	—		—	—	—	—	—	—	0%
	2017	2,837	—	—	—	—	—	—	2,837	0%
Timothy Woodall[5]	2018	38,889	—	—	3,694	—	—	—	42,583	0%
	2017	—	—	—	—	—	—	—	—	—
Sub-total	2018	432,297	—	912	41,068	—	—	—	474,277	0%
	2017	267,837	—	15,510	25,175	—	—	9,451	317,973	3%
Executive Directors and Other Key Management Personnel										
Richard Cottee	2018	565,954	—	16,550	20,049	—	16,988	713,704	1,333,245	54%
	2017	607,706	51,888	7,738	19,616	—	18,970	1,445,743	2,151,661	67%
Leon Devaney	2018	517,512	—	5,460	24,085	—	19,483	110,740	677,280	16%
	2017	412,005	39,346	4,305	28,163	—	9,082	91,951	584,852	16%
Ross Evans[7]	2018	31,411	—	—	2,771	—	316	—	34,498	0%
	2017	—	—	—	—	—	—	—	—	N/A
Michael Herrington	2018	523,557	—	6,280	23,634	—	13,696	149,623	716,790	21%
	2017	474,166	36,103	17,577	36,109	—	11,006	139,875	714,836	20%
Robin Polson[6]	2018	53,846	—	—	4,750	—	543	—	59,139	0%
	2017	—	—	—	—	—	—	—	—	N/A
Daniel White	2018	384,336	17,900	5,460	23,417	—	8,730	123,802	563,645	22%
	2017	407,527	28,440	3,618	33,078	—	7,525	111,084	591,272	19%
Sub-total	2018	2,076,616	17,900	33,750	98,706	—	59,756	1,097,869	3,384,597	32%
	2017	1,901,404	155,777	33,238	116,966	—	46,583	1,788,653	4,042,621	44%
Total Remuneration	**2018**	**2,508,913**	**17,900**	**34,662**	**139,774**	—	**59,756**	**1,097,869**	**3,858,874**	**28%**
	2017	2,169,241	155,777	48,748	142,141	—	46,583	1,798,104	4,360,594	41%

1 *Non-monetary benefits includes fringe benefits tax.*
2 *Robert Hubbard retired 14 May 2018*
3 *Martin Kriewaldt and Sarah Ryan were appointed Directors effective 23 October 2017.*
4 *J Thomas Wilson resigned as Director 15 July 2016*
5 *Timothy Woodall was appointed Director effective 20 December 2017*
6 *Robin Polson commenced 1 May 2018*
7 *Ross Evans commenced 1 June 2018*
8 *Short Term Incentives are unpaid at the end of the financial year. Amounts are shown in respect of the performance year to which they relate.*
The fair values of deferred share rights granted are valued using methodology that takes into account market and peer performance hurdles. The values are calculated at the date of grant using a Black Scholes valuation model with Monte Carlo simulations and an agreed comparator group to assess relative total shareholder return. The values are allocated to each reporting period evenly over the period from grant date to vesting date.

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during the 2018 year:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER RIGHT	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
01 Sep 2017	3 Oct 2022	$0.081	Nil	$0.115	87%	2.22%	0.00%
29 Nov 2017	18 Dec 2022	$0.055	Nil	$0.084	87%	2.09%	0.00%
27 Jun 2018	28 Jun 2023	$0.102	Nil	$0.150	87%	2.30%	0.00%

The following factors and assumptions were used in determining the fair value of share rights granted during the 2017 year:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER RIGHT	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
20 Oct 2016	8 Dec 2022	$0.106	Nil	$0.135	86%	1.86%	0.00%
16 Nov 2016	8 Dec 2022	$0.072	Nil	$0.185	92%	2.05%	0.00%
16 Nov 2016	8 Dec 2022	$0.151	Nil	$0.185	92%	2.05%	0.00%

Table 2: Share Based Compensation – Share Rights Granted during the Year

		NUMBER OF RIGHTS GRANTED	GRANT DATE	AVERAGE FAIR VALUE AT GRANT DATE	AVERAGE EXERCISE PRICE PER RIGHT	EXPIRY DATE
Richard Cottee	2018	1,835,910	29 Nov 17	$0.055	$0.000	18 Dec 22
	2018	18,319	29 Nov 17	$0.084	$0.000	18 Dec 22
	2017	3,202,983	16 Nov 16	$0.151	$0.000	08 Dec 22
Leon Devaney	2018	754,705	01 Sep 17	$0.081	$0.000	03 Oct 22
	2018	26,714	29 Sep 17	$0.097	$0.000	22 Sep 20
	2018	135,920	27 Jun 18	$0.102	$0.000	28 Jun 23
	2017	1,311,533	20 Oct 16	$0.106	$0.000	08 Dec 22
Ross Evans[2]	2018	—	—	—	—	—
	2017	—	—	—	—	—
Michael Herrington	2018	892,835	01 Sep 17	$0.081	$0.000	03 Oct 22
	2018	38,222	29 Sep 17	$0.097	$0.000	22 Sep 20
	2017	1,557,666	16 Nov 16	$0.151	$0.000	08 Dec 22
	2017	398,571	16 Nov 16	$0.072	$0.000	08 Dec 22
Robin Polson[1]	2018	—	—	—	—	—
	2017	—	—	—	—	—
Daniel White	2018	736,319	01 Sep 17	$0.081	$0.000	03 Oct 22
	2018	31,647	29 Sep 17	$0.097	$0.000	22 Sep 20
	2017	1,289,666	16 Nov 16	$0.151	$0.000	08 Dec 22

1 *Robin Polson commenced 1 May 2018*
2 *Ross Evans commenced 1 June 2018*

Table 3: Share Based Compensation – Share Rights Vested during the Year

		MAXIMUM NUMBER OF RIGHTS ELIGIBLE FOR VESTING	LONG TERM INCENTIVE PLAN YEAR COMMENCING	VESTING DATE	NUMBER OF RIGHTS VESTED[1]	PROPORTION OF RIGHTS VESTED[2]
Richard Cottee	2018	209,350	01 Jul 14	15 Dec 17	104,675	50%
	2017	—	—	—	—	—
Leon Devaney	2018	305,285	01 Jul 14	31 Oct 17	152,642	50%
	2017	—	—	—	—	—
Ross Evans[4]	2018	—	—	—	—	—
	2017	—	—	—	—	—
Michael Herrington	2018	436,793	01 Jul 14	31 Oct 17	218,396	50%
	2017	—	—	—	—	—
Robin Polson[3]	2018	—	—	—	—	—
	2017	—	—	—	—	—
Daniel White	2018	361,647	01 Jul 14	31 Oct 17	180,823	50%
	2017	—	—	—	—	—

1 *The number of rights that vested during the year relates to rights granted in prior financial years under the Long Term Incentive Plan*
2 *The proportion of rights vested represents the proportion of the maximum number of rights that were eligible for vesting during the financial year*
3 *Robin Polson commenced 1 May 2018*
4 *Ross Evans commenced 1 June 2018*

Table 4: Shareholdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF OPTIONS/RIGHTS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Wrixon Gasteen	2018	136,473	N/A	156,864	—	—	N/A	293,337
	2017	136,473	N/A	—	—	—	N/A	136,473
Robert Hubbard[1]	2018	298,947	N/A	365,667	—	—	664,614	N/A
	2017	298,947	N/A	—	—	—	N/A	298,947
Martin Kriewaldt[2]	2018	N/A	200,000	900,000	—		N/A	1,100,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Peter Moore	2018	—	—	265,000	—	—	N/A	265,000
	2017	—	—	—	—	—	N/A	—
Sarah Ryan[2]	2018	N/A	—	105,000	—	—	N/A	105,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Timothy Woodall[3]	2018	N/A	1,000,000	500,000	—	—	N/A	1,500,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Executive Directors and Other Key Management Personnel								
Richard Cottee	2018	571,829	N/A	216,929	104,675	(3,500)[4]	N/A	889,933
	2017	632,438	N/A	—	—	(60,609)[4]	N/A	571,829
Leon Devaney	2018	210,000	N/A	266,380	152,642	—	N/A	629,022
	2017	210,000	N/A	—	—	—	N/A	210,000
Ross Evans[6]	2018	N/A	—	—	—	—	N/A	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Michael Herrington	2018	250,000	N/A	104,168	218,396	—	N/A	572,564
	2017	250,000	N/A	—	—	—	N/A	250,000
Robin Polson[5]	2018	N/A	—	—	—	—	N/A	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Daniel White	2018	288,000	N/A	160,000	180,823	—	N/A	628,823
	2017	288,000	N/A	—	—	—	N/A	288,000

1 *Robert Hubbard retired 14 May 2018*
2 *Martin Kriewaldt and Sarah Ryan were appointed Directors 23 October 2017*
3 *Timothy Woodall was appointed Director 20 December 2017*
4 *Shares held by members of Mr Cottee's family no longer considered under his control have been removed from this table. No shares were sold by Mr Cottee during the 2017 year*
5 *Robin Polson commenced 1 May 2018*
6 *Ross Evans commenced 1 June 2018*

Table 5: Option Holdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	OPTIONS EXERCISED	GRANTED AS REMUNERATION	EXPIRED	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors							
Wrixon Gasteen	2018	—	—	—	—	N/A	—
	2017	666,666	—	—	(666,666)	N/A	—
Executive Directors and Other Key Management Personnel							
Richard Cottee	2018	24,900,773	—	—	(24,900,773)	N/A	—
	2017	24,900,773	—	—	—	N/A	24,900,773
Michael Herrington	2018	—	—	—	—	N/A	—
	2017	1,950,000	—	—	(1,950,000)	N/A	—
Daniel White	2018	—	—	—	—	N/A	—
	2017	760,000	—	—	(760,000)	N/A	—
Leon Devaney	2018	—	—	—	—	N/A	—
	2017	504,000	—	—	(504,000)	N/A	—

No employee options were outstanding at the end of the financial year and no options were exercised during the current or prior financial year.

Deferred Share Holdings of Key Management Personnel

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year.

The maximum number of rights to ordinary shares in the Company under the long term incentive plan held during the financial year by other key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

Table 6: Deferred Share Holdings of Key Management Personnel

		NUMBER OF RIGHTS HELD AT START OF YEAR	MAXIMUM NUMBER GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	CONVERTED TO SHARES	NUMBER OF RIGHTS HELD AT END OF YEAR (UNVESTED)
Executive Directors and Other Key Management Personnel						
Richard Cottee	2018	5,307,887	1,854,229	(104,675)	(104,675)	6,952,766
	2017	2,104,904	3,202,983	—	—	5,307,887
Leon Devaney	2018	2,373,104	917,339	(152,643)	(152,642)	2,985,158
	2017	1,061,571	1,311,533	—	—	2,373,104
Michael Herrington	2018	2,886,237	931,057	(218,397)	(218,396)	3,380,501
	2017	930,000	1,956,237	—	—	2,886,237
Daniel White	2018	2,389,666	767,966	(180,824)	(180,823)	2,795,985
	2017	1,100,000	1,289,666	—	—	2,389,666

G. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity are as follows:

Richard Cottee, Managing Director and Chief Executive Officer

- As announced, Mr Cottee's employment will end on the 31st January 2019.
- Mr Cottee's base salary is presently $598,654 per annum. In addition, superannuation at 9.5% subject to the statutory limit is applicable.

Leon Devaney, Chief Financial Officer & Acting Chief Executive Officer

- The term of the agreement expires 1st July 2022.
- Mr Devaney's base salary is presently $505,000 per annum. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a 6 month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Ross Evans, Chief Operations Officer (commenced 1 June 2018)

- The term of the agreement expires 1 June 2021.
- Mr Evan's base salary is presently $356,650 per annum. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a 6-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Mike Herrington, President – Operations and Chief Development Officer

- The term of the agreement expires 29 January 2019.
- Mr Herrington's base salary is presently $485,226 per annum. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a 3-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Robin Polson, Chief Commercial Officer (Commenced 1 May 2018)

- The term of the agreement expires 1 May 2021.
- Mr Polson's base salary is presently $300,000 per annum. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a 6-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Daniel White, Group General Counsel and Company Secretary

- The term of the agreement expires 30 November 2021.
- Mr White's base salary is presently $400,164 per annum. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a 3-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

H. Non-Executive Director Fee Arrangements

The Company has engaged all Directors pursuant to written service agreements. The terms of appointment are subject to the Company's constitution. The Company maintains an appropriate level of Directors' and Officers' Liability Insurance and provide rights relating to indemnity, insurance, and access to documents.

The table below summarises the Non-Executive Director fees for 2018.

BOARD FEES (PER ANNUM)

Chairman	$130,000.00
Non-Executive Director	$70,000.00

COMMITTEE FEES (PER ANNUM)

Audit	Chair	$10,000.00
	Member	$5,000.00
Risk	Chair	$10,000.00
	Member	$ Nil
Remuneration & Nominations	Chair	$10,000.00
	Member	$5,000.00

The directors also receive superannuation benefits.

Signed in accordance with a resolution of the directors:

Martin Kriewaldt
Chairman
Brisbane

28 September 2018

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2018, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Central Petroleum Limited and the entities it controlled during the period.

Michael Shewan
Partner
PricewaterhouseCoopers

Brisbane
28 September 2018

CORPORATE GOVERNANCE STATEMENT

Central Petroleum Limited and the Board are committed to achieving and demonstrating high standards of corporate governance. The Company has reviewed its corporate governance practices against the Corporate Governance Principles and Recommendations (3rd edition) published by the ASX Corporate Governance Council.

The 2018 Corporate Governance Statement is dated as at 30 June 2018 and reflects the corporate governance practices in place throughout the 2018 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

FINANCIAL REPORT

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These Financial Statements are the consolidated financial statements of the Group, consisting of Central Petroleum Limited and its subsidiaries.

The Financial Statements are presented in Australian currency.

Central Petroleum Limited is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is:

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the review of operations and activities which forms part of the Directors' Report on pages 4 to 32. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 28 September 2018. The Directors have the power to amend and reissue the financial statements.

Through the use of the internet we have ensured that our corporate reporting is timely and complete. Press releases, financial reports and other information are available via the links on our website: www.centralpetroleum.com.au.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2018

	NOTE	2018 $	2017 $
Revenue from the sale of goods	23	34,939,194	24,794,145
Cost of sales		(18,704,042)	(15,701,690)
Gross profit		16,235,152	9,092,455
Other income	2	1,055,184	3,114,038
Share based employment benefits	31(d)	(1,622,329)	(2,251,024)
General and administrative expenses		(595,925)	(1,946,659)
Depreciation and amortisation	3(a)	(8,033,092)	(7,780,576)
Employee benefits and associated costs		(4,061,759)	(5,658,990)
Exploration expenditure		(8,790,052)	(1,901,382)
Finance costs	3(a)	(7,848,877)	(7,812,071)
Revaluation of financial liabilities	3(a)	(414,431)	(9,493,259)
Impairment expense	3(a)	—	(89,013)
Loss before income tax		(14,076,129)	(24,726,481)
Income tax credit	4	—	—
Loss for the year		(14,076,129)	(24,726,481)
Other comprehensive loss for the year, net of tax		—	—
Total comprehensive loss for the year		(14,076,129)	(24,726,481)
Total comprehensive loss attributable to members of the parent entity		**(14,076,129)**	**(24,726,481)**
Basic and diluted loss per share (cents)	22	(2.13)	(5.71)

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 30 JUNE 2018

	NOTE	2018 $	2017 $
ASSETS			
Current assets			
Cash and cash equivalents	6	27,222,845	5,478,140
Trade and other receivables	7	6,631,642	4,996,216
Inventories	8	3,575,480	3,273,014
Other financial assets	12	2,333,333	—
Total current assets		39,763,300	13,747,370
Non-current assets			
Property, plant and equipment	9	103,853,369	106,816,359
Exploration assets	10	8,898,767	8,898,767
Intangible assets	11	156,017	82,157
Other financial assets	12	2,535,915	2,501,947
Goodwill	13	3,906,270	3,906,270
Total non-current assets		119,350,338	122,205,500
Total assets		**159,113,638**	**135,952,870**
LIABILITIES			
Current liabilities			
Trade and other payables	14	8,113,667	3,239,168
Deferred revenue	15	7,283,068	2,714,334
Interest-bearing liabilities	16	3,727,338	3,859,747
Other financial liabilities	18	38,600	38,600
Provisions	17	3,406,515	3,161,454
Total current liabilities		22,569,188	13,013,303
Non-current liabilities			
Deferred revenue	15	13,678,980	5,283,741
Interest-bearing liabilities	16	74,599,221	78,310,007
Other financial liabilities	18	15,362,506	21,914,537
Provisions	17	25,840,435	23,389,129
Total non-current liabilities		129,481,142	128,897,414
Total liabilities		**152,050,330**	**141,910,717**
Net assets		**7,063,308**	**(5,957,847)**
EQUITY			
Contributed equity	19	197,776,487	172,301,532
Reserves	20	23,463,784	21,841,455
Accumulated losses	21	(214,176,963)	(200,100,834)
Total equity		**7,063,308**	**(5,957,847)**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 30 JUNE 2018

	CONTRIBUTED EQUITY $	RESERVES $	ACCUMULATED LOSSES $	TOTAL $
Balance at 1 July 2016	**172,301,532**	**19,590,431**	**(175,374,353)**	**16,517,610**
Total loss for the year	—	—	(24,726,481)	(24,726,481)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(24,726,481)	(24,726,481)
Transactions with owners in their capacity as owners				
Share based payments	—	2,251,024	—	2,251,024
Options issued for financing	—	—	—	—
Share and option issues	—	—	—	—
Share issue costs	—	—	—	—
	—	2,251,024	—	2,251,024
Balance at 30 June 2017	**172,301,532**	**21,841,455**	**(200,100,834)**	**(5,957,847)**
Total loss for the year	—	—	(14,076,129)	(14,076,129)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(14,076,129)	(14,076,129)
Transactions with owners in their capacity as owners				
Share based payments	—	1,622,329	—	1,622,329
Options issued for financing	—	—	—	—
Share and option issues	27,250,000	—	—	27,250,000
Share issue costs	(1,775,045)	—	—	(1,775,045)
	25,474,955	1,622,329	—	27,097,284
Balance at 30 June 2018	**197,776,487**	**23,463,784**	**(214,176,963)**	**7,063,308**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOW

FOR THE YEAR ENDED 30 JUNE 2018

	NOTE	2018 $	2017 $
Cash flows from operating activities			
Receipts from customers		39,285,428	27,628,945
Interest received		494,077	165,581
Other income		25,660	667,355
Interest and borrowing costs		(5,987,298)	(6,347,719)
Payments to suppliers and employees (inclusive of GST)		(28,644,637)	(22,348,163)
Net cash inflow/(outflow) from operating activities	27	5,173,230	(234,001)
Cash flows from investing activities			
Payments for property, plant and equipment		(2,999,815)	(1,297,122)
Payments for interest in Mereenie Joint Venture		—	(3,342,446)
Proceeds from sale of property, plant and equipment		33,636	99,591
Proceeds and deposits for the disposal of exploration permits		430,000	—
(Acquisition)/Redemption of security deposits and bonds		(2,367,302)	(863,581)
Net cash outflow from investing activities		(4,903,481)	(5,403,558)
Cash flows from financing activities			
Proceeds from the issue of shares and options		27,250,000	—
Payments for capital raising costs		(1,775,044)	—
Proceeds from borrowings and other financing arrangements		—	—
Repayment of borrowings	28	(4,000,000)	(4,000,000)
Net cash inflow/(outflow) from financing activities		21,474,956	(4,000,000)
Net increase/(decrease) in cash and cash equivalents		**21,744,705**	**(9,637,559)**
Cash and cash equivalents at the beginning of the financial year		**5,478,140**	**15,115,699**
Cash and cash equivalents at the end of the financial year	6	**27,222,845**	**5,478,140**

The accompanying notes form part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated. The financial statements are for the consolidated entity consisting of Central Petroleum Limited ("the Company") and its subsidiaries (collectively "the Group" or "the Consolidated Entity").

(a) Basis of Preparation

These general purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board and the *Corporations Act 2001*. Central Petroleum Limited is a for-profit entity for the purpose of preparing the financial statements.

(i) Going Concern

The Directors have prepared the financial statements on a going concern basis which contemplates continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business.

The Group incurred a net loss for the year of $14,076,129, a net positive cash flow from operations of $5,173,230 and an overall net asset position of $7,063,308. The Group continually monitors its cash flow requirements to ensure it has sufficient funds to meet its contractual commitments and adjust its spending, particularly with respect to discretionary exploration activity and corporate overhead, accordingly. Supported by the cash assets at 30 June 2018 of $27,222,845, and its cash flow forecasts, the Group forecasts that over at least the next 12 months, it will have sufficient funds to meet its commitments and continue to pay its debts as and when they fall due. The Company has $12.5 million undrawn debt available under the Macquarie debt facility (refer Notes 32 (e) and 34) and a further $5 million available under a partial pre-payment in relation to the recently announced IPL GSA. In addition the Company has signed a $10 million Equity Line of Credit with Long State Investment Limited (refer Note 34).

The net asset position of $7,063,308 includes financial liabilities of $15,362,506 and deferred revenue liabilities of $7,865,982 recorded in respect of the Macquarie Bank Limited Gas Sale and Pre-payment Agreement entered into in May 2016 as discussed in Note 3(b). At the time of settlement over the three year term, the liability will be satisfied by the physical delivery of gas from existing 1P reserves through 2019, after which it may be satisfied at the election of Macquarie by either the physical delivery of gas or paid out of the proceeds of the sale of gas contracted under the EDL GSA for which no asset has been recognised in the accounts.

Accordingly, the Directors believe the going concern assumption is appropriate.

(ii) Compliance with IFRS

The consolidated financial statements of the Central Petroleum Limited Group also comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board ("IASB").

(iii) Early Adoption of Standards

The Group has not applied any pronouncements to the annual reporting period beginning on 1 July 2017 where such application would result in them being applied prior to them becoming mandatory.

(iv) Historical Cost Convention

These financial statements have been prepared under the historical cost convention.

(v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty

In the application of the Group's accounting policies, management is required to make judgements, estimates and assumptions regarding carrying values of assets and liabilities that are not readily apparent from other sources. The estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements. Actual results may differ from these estimates. Key judgements in applying the entity's accounting policies are required in the following areas:

Rehabilitation

The Group recognises any obligations for removal and restoration that are incurred during a particular period as a consequence of having undertaken exploration and evaluation activity. The Group makes provision for future restoration expenditure relating to work previously undertaken based on management's estimation of the work required.

Share-based Payments

The Group is required to use assumptions in respect of their fair value models, and the variable elements in these models, used in determining share based payments. The Directors have used a model to value options and rights, which requires estimates and judgements to quantify the inputs used by the model.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

(v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty (continued)

Impairment of Capitalised Exploration and Evaluation Expenditure

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the lease itself or, if not, whether it successfully recovers the related exploration and evaluation expenditure through sale. Factors that impact recoverability may include, but are not limited to, the level of resources and reserves, the cost of production, legal changes and commodity price changes. Acquisition expenditure is capitalised if activities in the area of interest have not yet reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves. To the extent that the capitalised acquisition expenditure is determined not to be recoverable in future, profits and net assets will be reduced in the period in which this determination is made.

Impairment of Other Non-financial Assets

Other non-financial assets, including property, plant and equipment and goodwill are tested for impairment annually or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). The Group is required to use assumptions in respect of future commodity prices, foreign exchange rates, interest rates and operating costs in determining expected future cash flows from operations.

Other Financial Liabilities

The group may be required to use assumptions in respect of expected future gas prices in respect of gas sales agreements that contain a financial settlement option. The expected future financial settlements reference expected future gas sales volumes and prices and the terms of individual agreements (refer to Note 18 for further details).

Taxation

The Group's accounting policy for taxation requires management's judgement in relation to the types of arrangements considered to be a tax on income in contrast to an operating cost. Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Statement of Financial Position. Deferred tax assets, including those arising from un-recouped tax losses, capital losses, and temporary differences arising from the *Petroleum Resource Rent Tax (Imposition – General) Act 2011*, are recognised only where it is considered more likely than not they will be recovered, which is dependent on the generation of sufficient future taxable profits.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Statement of Financial Position and the amount of other tax losses and temporary differences not yet recognised. In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Comprehensive Income.

(b) Principles of Consolidation

(i) Subsidiaries

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of Central Petroleum Limited ("the Company" or "Parent Entity") as at 30 June and the results of all subsidiaries for the year then ended. Central Petroleum Limited and its subsidiaries together are referred to in this financial report as "the Group" or "the Consolidated Entity".

Subsidiaries are all entities (including structured entities) over which the group has control. The group controls an entity when the group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the group.

They are deconsolidated from the date that control ceases. The acquisition method is used to account for business combinations by the Group.

Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of the impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation (continued)

Non-controlling interests (if applicable) in the results and equity of subsidiaries are shown separately in the statement of comprehensive income, statement of changes in equity and statement of financial position respectively.

(ii) Joint Arrangements

The Group's investments in joint arrangements are classified as either joint operations or joint ventures; depending on the contractual rights and obligations each investor has, rather than the legal structure of the joint arrangement.

The Group's exploration and production activities are conducted through joint arrangements governed by joint operating agreements or similar contractual relationships.

A joint operation involves the joint control, and often the joint ownership, of one or more assets contributed to, or acquired for the purpose of, the joint operation and dedicated to the purposes of the joint operation. The assets are used to obtain benefits for the parties to the joint operation. Each party may take a share of the output from the assets and each bears an agreed share of expenses incurred. Each party has control over its share of future economic benefits through its share of the joint operation. The interests of the Group in joint operations are brought to account by recognising in the financial statements the Group's share of jointly controlled assets, share of expenses and liabilities incurred, and the income from the sale or use of its share of the production of the joint operation in accordance with the revenue policy in note 1(e). Details of the joint operations are set out in Note 33.

(c) Segment Reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the Executive Management Team.

(d) Foreign Currency Translation

(i) Functional and Presentation Currency

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in Australian dollars, which is Central Petroleum Limited's functional currency and presentation currency.

(ii) Transactions and Balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss, except when they are deferred in equity as qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

(e) Revenue Recognition

Revenue is recognised and measured at the fair value of the consideration received or receivable, net of goods and services tax, to the extent it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. The following specific recognition criteria must also be met before revenue is recognised:

(i) Sale of Oil and Gas / Deferred Revenue

Revenue is recognised when the significant risks and rewards of ownership of the product have passed to the buyer and the amount of revenue can be measured reliably. Risks and rewards are considered to have passed to the buyer at the time of delivery of the product to the customer. Revenue from take or pay contracts is recognised in earnings when the product is taken by the customer or their right to take product expires. It is recorded as liability (deferred revenue) when it has not been taken and a right to take it in future still exists.

(ii) Interest Income

Interest revenue is recognised on a time proportionate basis that takes into account the effective yield on the financial assets.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(f) Government Grants

Grants from the government, including research and development concessions, are recognised at their fair value where there is a reasonable assurance that the grant or refund will be received and the Group has or will comply with any conditions attaching to the grant or refund. Research and development grants are recognised as other income in the profit and loss where they relate to exploration expenditure which has been expensed in the profit and loss.

(g) Income Tax

The income tax expense or revenue for the period is the tax payable on the current period's taxable income based on the applicable income tax rate adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantially enacted at the end of the reporting period in the countries where entities in the Group generate taxable income.

Deferred tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that, at the time of the transaction, affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the Group is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

Central Petroleum Limited and its wholly-owned Australian controlled entities have implemented the tax consolidation legislation. As a consequence, these entities are taxed as a single entity and the deferred tax assets and liabilities of these entities are set off in the consolidated financial statements. Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

(h) Leases

Leases of property, plant and equipment where the Group, as lessee, has substantially all the risks and rewards of ownership are classified as finance leases. Finance leases are capitalised at the lease's inception at the fair value of the leased property or, if lower, the present value of the minimum lease payments. The corresponding rental obligations, net of finance charges, are included in other short-term and long-term payables. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to the profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The property, plant and equipment acquired under finance leases is depreciated over the asset's useful life or over the shorter of the asset's useful life and the lease term if there is no reasonable certainty that the Group will obtain ownership at the end of the lease term.

Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset and the lease term if there is no reasonable certainty that the Consolidated Entity will obtain ownership by the end of the lease term.

Leases in which a significant portion of the risks and rewards of ownership are not transferred to the Group as lessee are classified as operating leases (Note 30(c)). Payments made under operating leases (net of any incentives received from the lessor) are charged to profit or loss on a straight-line basis over the period of the lease.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(i) Impairment of Assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

(j) Cash and Cash Equivalents

For the purpose of presentation in the statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of 3-months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts (if applicable) are shown within borrowings in current liabilities in the statement of financial position.

(k) Trade Receivables

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. Trade receivables are generally due for settlement within 90 days. They are presented as current assets unless collection is not expected for more than 12-months after the reporting date.

Collectability of trade receivables is reviewed on an ongoing basis. Debts which are known to be uncollectible are written off by reducing the carrying amount directly. An allowance account (provision for impairment of trade receivables) is used when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or delinquency in payments (more than 90 days overdue) are considered indicators that the trade receivable is impaired. The amount of the impairment allowance is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial.

The amount of the impairment loss is recognised in profit or loss within other expenses. When a trade receivable for which an impairment allowance had been recognised becomes uncollectible in a subsequent period, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against other expenses in profit or loss.

(l) Inventories

Inventories comprise hydrocarbon stocks, drilling materials and spare parts and are valued at the lower of cost and net realisable value. Costs are assigned to individual items of inventory on a first in first out or weighted average cost basis. Cost of inventory includes the purchase price after deducting any rebates and discounts, as well as any associated freight charges.

Net realisable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

(m) Other Financial Assets

Classification

The Group's financial assets consist of loans and receivables. These are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for those with maturities greater than 12-months after the reporting period which are classified as non-current assets. Loans and receivables are included in trade and other receivables (Note 7) and other financial assets (Note 12) in the statement of financial position. Amounts paid as performance bonds or amounts held as security for bank guarantees in satisfaction of performance bonds are classified as other financial assets.

Measurement

At initial recognition, the Group measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss. Loans and receivables are subsequently carried at amortised cost using the effective interest method.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(n) Property, Plant and Equipment – Development and Production Assets

Assets in Development

The costs of oil and gas properties in the development phase are separately accounted for and include costs transferred from exploration and evaluation assets once technical feasibility and commercial viability of an area of interest are demonstrable. When production commences, the accumulated costs are transferred to producing areas of interest except for land and buildings and surface plant and equipment associated with development assets which are recorded in the land and buildings and plant and equipment categories respectively. Amortisation is not charged on costs carried forward in respect of areas of interest in the development phase until production commences.

Producing Assets

The costs of oil and gas properties in production are separately accounted for and include costs transferred from exploration and evaluation assets, transferred development assets and the ongoing costs of continuing to develop reserves for production including an estimate of the costs to restore the site. Land and buildings and surface plant and equipment associated with producing areas of interest are recorded in the other land and buildings and other plant and equipment categories respectively.

Depreciation of producing assets is calculated using the units of production method for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method which will amortise the cost of carried forward exploration, evaluation and subsurface development expenditure ("subsurface assets") over the life of the estimated Proven plus Probable (2P) hydrocarbon reserves for an asset or group of assets, together with future subsurface costs necessary to develop the hydrocarbon reserves included in the calculation.

(o) Property, Plant and Equipment – Other than Development and Production Assets

All property, plant and equipment is stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Cost may also include transfers from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance costs are charged to profit or loss during the reporting period in which they are incurred.

Land is not depreciated. Depreciation of plant and equipment is calculated on a reducing balance basis so as to write off the net costs of each asset over the expected useful life. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

Gains and losses on disposals are determined by comparing proceeds with the carrying amount. These are included in the profit or loss.

The expected useful life for each class of depreciable assets is:

Class of Fixed Asset	Expected Useful Life
Buildings	40 years
Leasehold Improvements	2 – 6 years
Plant and Equipment	2 – 30 years
Motor Vehicles	5 – 10 years

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(p) Exploration Expenditure

Exploration and evaluation costs are expensed as incurred. Acquisition costs of rights to explore are capitalised in respect of each separate area of interest and carried forward where right of tenure of the area of interest is current. These costs are expected to be recouped through sale or successful development and exploitation of the area of interest or where exploration and evaluation activities in the area of interest have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves. No amortisation is charged on acquisition costs capitalised under this policy.

When an area of interest is abandoned or the Directors decide that it is not commercial, any accumulated costs in respect of that area are written off in the financial period the decision is made. Each area of interest is also reviewed at the end of each accounting period and accumulated costs written off to the extent that they will not be recoverable in the future.

(q) Goodwill

Goodwill arising on the acquisition of subsidiaries is not amortised but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate a potential impairment. Goodwill is carried at cost less accumulated impairment losses.

Goodwill is allocated to cash generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose. The units or groups of units are identified at the lowest level at which goodwill is monitored for internal management purposes, being the operating segments (Note 23).

(r) Trade and Other Payables

These amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which are unpaid. The amounts are unsecured and are usually paid within 30 days of recognition, except contributions to Joint Arrangements that are settled in line with the Joint Operating Agreements. Trade and other payables are presented as current liabilities unless payment is not due within 12-months from the reporting date. They are recognised initially at their fair value and subsequently measured at amortised cost using the effective interest method.

(s) Provisions

(i) Restoration

The Group records the present value of the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas.

A restoration provision is recognised and updated at different stages of the development and construction of a facility and then reviewed on an annual basis. When the liability is initially recorded, the estimated cost is capitalised by increasing the carrying amount of the related exploration and evaluation assets or property plant and equipment. Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs.

The carrying amount capitalised in property plant and equipment is depreciated over the useful life of the related producing asset (refer to Note 1(n)).

Costs incurred that relate to an existing condition caused by past operations and do not have a future economic benefit are expensed.

(ii) Onerous Contracts

An Onerous Contracts provision is recognised where the unavoidable costs of meeting obligations under the contract exceeds the value of the economic benefits expected to be received under the contract.

(iii) Other

Provisions for legal claims and make good obligations are recognised when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount has been reliably estimated. Provisions are not recognised for future operating losses.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions (continued)

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as interest expense.

(t) Employee Benefits

(i) Short-term Obligations

Liabilities for wages and salaries, including non-monetary benefits, annual leave and long service leave expected to be settled within 12-months after the end of the period in which the employees render the related service are recognised in respect of employees' services up to the end of the reporting period and are measured at the amounts expected to be paid when the liabilities are settled. The liability for annual leave and long service leave is recognised in the provision for employee benefits. All other short-term employee benefit obligations are presented as payables.

(ii) Other Long-term Employee Benefit Obligations

The liability for long service leave which is not expected to be settled within 12-months after the end of the period in which the employees render the related service is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the end of the reporting period. Consideration is given to expected future wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted using market yields at the end of the reporting period with terms to maturity and currency that match, as closely as possible, the estimated future cash outflows.

(iii) Share-based Payments

Share-based compensation benefits are provided to employees by Central Petroleum Limited.

The fair value of options or rights granted is recognised as an employee benefits expense with a corresponding increase in equity. The total amount to be expensed is determined by reference to the fair value of the rights or options granted, which includes any market performance conditions and the impact of any non-vesting conditions but excludes the impact of any service and non-market performance vesting conditions.

Non-market vesting conditions are included in assumptions about the number of options that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each period, the entity revises its estimates of the number of options that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in profit or loss, with a corresponding adjustment to equity.

(iv) Termination Benefits

Termination benefits are payable when employment is terminated by the Group before the normal retirement date, or when an employee accepts voluntary redundancy in exchange for these benefits.

The Group recognises termination benefits at the earlier of the following dates: (a) when the Group can no longer withdraw the offer of those benefits; and (b) when the entity recognises costs for a restructuring that is within the scope of AASB 137 and involves the payment of terminations benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer. Benefits falling due more than 12-months after the end of the reporting period are discounted to present value.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(u) Contributed Equity

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

(v) Dividends

Provision is made for the amount of any dividend declared, being appropriately authorised and no longer at the discretion of the entity, on or before the end of the reporting period but not distributed at the end of the reporting period.

(w) Earnings Per Share

(i) Basic Earnings Per Share

Basic earnings per share is calculated by dividing the profit attributable to owners of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year.

(ii) Diluted Earnings Per Share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of additional ordinary shares that would have been outstanding assuming the exercise of all dilutive potential ordinary shares.

(x) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the statement of financial position.

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financing activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

(y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 24, has been prepared on the same basis as the consolidated financial statements except as set out below.

(i) Investments in Subsidiaries, Associates and Joint Venture Entities

Investments in subsidiaries, associates and joint venture entities are accounted for at cost in the financial statements of Central Petroleum Limited.

(ii) Tax Consolidation Legislation

Central Petroleum Limited and its wholly-owned Australian controlled entities have implemented the income tax consolidation legislation. The head entity, Central Petroleum Limited, and the controlled entities in the income tax consolidated Group account for their own current and deferred tax amounts where recognition of such is permitted under accounting standards. These tax amounts are measured as if each entity in the tax consolidated Group continues to be a standalone taxpayer in its own right.

In addition to its own current and deferred tax amounts, Central Petroleum Limited also recognises the current tax liabilities or assets and the deferred tax assets arising from unused tax losses from controlled entities, where permitted to recognise such assets under accounting standards.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(z) Business Combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, the Group elects whether it measures the non-controlling interest in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date through profit or loss.

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 that is deemed to be an asset or liability will be recognised in accordance with AASB 139 in profit or loss. If the contingent consideration is classified as equity it will not be remeasured. Subsequent settlement is accounted for within equity. In instances where the contingent consideration does not fall within the scope of AASB 139, it is measured in accordance with the appropriate AASB.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognised in profit or loss.

After 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 each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquirer are assigned to those units.

Where goodwill forms part of the cash generating unit and part of the operation within that unit 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 values of the operation disposed of and the portion of the cash-generating unit retained.

(aa) Standards, Amendments and Interpretations

(i) New and Amended Standards Adopted by the Group

In the current period, the Group has adopted all new and revised Standards and Interpretations issued by the Australian Accounting Standards Board that are relevant to its operations and effective for reporting periods beginning on or after 1 July 2017. The adoption of these new and revised Standards and Interpretations has not resulted in any changes to the Group's accounting policies.

No changes in accounting policies or adjustments to the amounts recognised in the financial statements resulted from the adoptions of these standards.

(ii) New Standards and Interpretations not yet adopted

Certain new accounting standards and interpretations have been published that are not mandatory for the current reporting period.

(a) AASB 15 Revenue from contracts with customers

The AASB has issued a new standard for the recognition of revenue. This will replace AASB 111 *Construction Contracts*, AASB 118 *Revenue* and related IFRIC Interpretations. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer.

The new standard is mandatory for the Group from 1 July 2018 and permits either a full retrospective or a modified retrospective approach for the adoption. The Group intends to apply the full retrospective approach.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations (continued)

(ii) New Standards and Interpretations not yet adopted (continued)

Management has undertaken an assessment of the effects of applying the new standard applying the following steps:

- Identify contract with customers
- Identifying the performance obligations in the contract
- Determining the transaction price under the contract
- Considering how the transaction price will be allocated to the performance obligations in the contract
- Determining when revenue is recognized, upon satisfaction of performance obligations.

The Group has two types of revenue from customers being revenue from the sale of Natural Gas and revenue from the sale of Crude Oil.

Management has considered its natural gas sales and the impact of “take or pay” clauses included in long term gas sales agreements and has concluded that the current policy for revenue recognition is consistent with the requirements of AASB 15. As a result revenue recognised in respect of natural gas sales will not be impacted by the new standard based on current operations.

Crude oil is currently delivered to a sales point at Port Bonython and is invoiced in USD. The final oil price is calculated under a formula, the calculation of which is contingent upon the date the crude is “lifted” from the Port. Management has concluded that the current policy for revenue recognition satisfies the requirements of AASB 15.

The Group does not currently enter into any gas swap arrangements nor is it in any “under-lift” position which may impact revenue recognition.

(b) AASB 9 Financial Instruments

AASB 9 Financial Instruments addresses the classification, measurement and derecognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new impairment model. The standard is mandatory for the Group from 1 July 2018 and the Group has not early adopted the new standard.

The Group has undertaken an assessment of the changes, and concluded that there will be no impact from the new classification, measurement and derecognition rules on the Group’s financial assets and financial liabilities.

The Group does not currently enter into any hedge transactions and will not be affected by the new rules.

The new impairment model is an expected credit loss (“ECL”) model. The Group does not currently have any impairment provision for credit losses. Receivables relate to credit worthy customers and Joint Venture partners and are collected in accordance with contractual requirements.

(c) AASB 16 Leases

AASB 16 was issued in February 2016. It will result in almost all leases being recognised on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognised. The only exceptions are short-term and low-value leases.

The standard will affect primarily the accounting for the Group’s operating leases. As at the reporting date, the Group has operating lease commitments of $1,748,364. The Group expects the majority of these commitments will be recorded as a Lease Liability on the balance sheet under AASB 16, however has not yet determined the exact extent that this will affect the Group’s profit and classification of cash flows. Some of the commitments may be covered by the exception for short-term and low-value leases and some commitments may relate to arrangements that will not qualify as leases under AASB 16.

The standard is mandatory for annual reporting periods beginning on or after 1 January 2019 which, for the Group, will be from 1 July 2019. The group does not expect to adopt the standard early.

2. OTHER INCOME

	2018 $	2017 $
Interest	525,109	149,481
Research and development refunds (a)	—	634,167
Forgiveness of amounts due under Joint ventures (b)	—	2,017,203
Sale of exploration permits	280,000	280,000
Profit on disposal of inventory and other assets	224,415	—
Other income	25,660	33,187
Total other income	**1,055,184**	**3,114,038**

(a) The research and development refunds received in 2017 were in respect of the financial year ended 30 June 2016 and were not previously recognised as income as the amount and recoverability were uncertain at the time of preparation of the 2016 financial statements.

(b) Under the terms of the Southern Georgina Farmout Agreement between wholly owned subsidiary Merlin Energy Pty Ltd ("Merlin") and Total GLNG Australia ("Total"), Total were required to pay for the first 80% of Stage 1 farmin expenditure and Merlin Energy were required to pay for the last 20%. In February 2017, Total elected not to proceed to Stage 2 of the Farmin and to withdraw from the Joint Venture. The Deed of Assignment, Assumption and Transfer of Total's interests included releasing Merlin from all amounts accrued up to the date of withdrawal by Total.

3. EXPENSES

(a) Loss before income tax includes the following specific expenses

	NOTE	2018 $	2017 $
Depreciation			
Buildings		350,202	349,297
Producing assets		3,657,662	2,553,914
Plant and equipment		3,950,098	4,808,986
Leasehold improvements		33,414	41,183
Total depreciation		7,991,376	7,753,380
Amortisation			
Software		41,716	27,196
Impairment expense		—	89,013
Rental expense relating to operating leases – Minimum lease payments		609.396	518,088
Revaluation of financial liabilities	3(b)	414,431	9,493,259
Finance costs			
Interest charge on Macquarie debt facility		6,003,851	6,328,742
Interest paid to other suppliers		—	18,737
Interest on other financial liabilities		938,119	533,774
Borrowing costs on Macquarie and other debt facilities		—	240
Amortisation of deferred finance costs		393,147	485,725
Accretion charge		513,760	444,853
		7,848,877	7,812,071

(b) Individually significant items

Revaluation of financial liabilities

In 2016 the Group entered into a Gas Sale and Prepayment Agreement (“GSPA”) with Macquarie Bank Limited (“MBL”), to commence following completion of the Northern Gas Pipeline. Under the agreement Macquarie may elect to receive a financial settlement in lieu of taking physical delivery of gas. The financial settlement amount, if so elected, is dependent on the ex-field price received by the Group under any new gas sales agreements from the designated production area.

As a result of the Group signing a new gas sales agreement during the 2017 year, under the applicable accounting standards, it was necessary to re-assess the value of the financial settlement option under the Gas Sale and Prepayment Agreement. This resulted in an increase in the recorded financial liability of $9,493,259 in the 2017 financial year.

In the 2018 financial year adjustments were made to the value of the financial liability to reflect the latest pricing and quantity assumptions of the underlying agreements, as well as the expected completion date for the Northern Gas Pipeline, all of which impact either the timing or amount of any potential financial settlement. These adjustments related in a total increase in the recorded financial liability amounting to $414,431.

In June 2018 MBL novated its rights under the first year of the GSPA to Incitec Pivot Limited (refer also Note 18). As a result the first year obligations will be satisfied by physical delivery of gas. For subsequent years it will be satisfied by either the physical delivery of gas or paid out of the proceeds of the sale of gas contracted under the GSA’s for which no asset has been recognised in the accounts.

4. INCOME TAX

This note provides an analysis of the Group's income tax expense, shows what amounts are recognised directly in equity and how the tax credit is affected by non-assessable and non-deductible items. It also explains significant estimates made in relation to the Group's tax position.

		2018 $	2017 $
(a)	**Income tax expense**		
	Current tax	—	—
	Deferred tax	—	—
	Income tax expense	—	—
(b)	**Numerical reconciliation of income tax expense and prima facie tax benefit**		
	Loss before income tax expense	(14,076,129)	(24,726,481)
	Prima facie tax benefit at 30% (2017: 30%)	4,222,839	7,417,944
	Tax effect of amounts which are not deductible in calculating taxable income:		
	Non-deductible expenses	(309,262)	(147,002)
	Share based payments	(486,699)	(675,307)
	Non-assessable income (R&D Refund)	—	190,250
	Other items	1,181	—
	Sub-total	3,428,059	6,785,885
	Under provision in prior year		—
	Deferred tax assets not recognised	(3,428,059)	(6,785,885)
	Recognition of previously unrecognised DTA	—	—
	Income tax expense	—	—
(c)	**Amounts recognised directly in equity**		
	Aggregate deferred tax arising in the reporting period and not recognised in net profit or loss or other comprehensive income but directly debited or credited to equity:		
	Net deferred tax – debited directly to equity	532,514	—
	Deferred tax assets not recognised	(532,514)	—
	Net amounts recognised directly in equity	—	—
(d)	**Tax Losses**		
	Unutilised tax losses for which no deferred tax asset has been recognised	131,114,647	120,670,253
	Potential tax benefit at 30%	39,334,394	36,201,076

Unutilised tax losses are available for use in Australia and are available to offset future taxable profits of the income tax consolidated group, subject to the relevant tax loss recoupment requirements being met.

4. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2018 $	2017 $
Deferred tax assets		
Provisions and accruals	8,875,664	8,073,231
Financial liabilities	2,238,662	3,020,191
Deferred revenue	1,187,294	—
Future deductible expenditure	—	517,500
Blackhole expenditure	848,653	633,119
Borrowing costs	51,121	130,099
PRRT	244,162,165	222,245,877
Unutilised losses	49,740,525	46,462,857
Total deferred tax assets before set-offs	307,104,084	281,082,874
Set-off of deferred tax liabilities pursuant to set-off provisions	(13,916,012)	(12,050,541)
Net deferred tax assets not recognised	**293,188,072**	**269,032,333**
Movements		
Opening balance at 1 July	12,050,541	10,720,341
(Charged) / Credited to the income statement	1,865,471	1,330,200
Closing balance at 30 June	13,916,012	12,050,541
Deferred tax assets to be recovered after more than 12-months	12,060,386	10,849,394
Deferred tax assets to be recovered within 12-months	1,855,626	1,201,147
	13,916,012	12,050,541
Deferred tax liabilities		
Acquired income	12,061	4,007
Capitalised exploration	463,254	450,254
Property, plant and equipment	9,930,815	9,296,490
PRRT	3,509,882	2,299,790
Total deferred tax assets before set-offs	13,916,012	12,050,541
Set-off of deferred tax liabilities pursuant to set-off provisions	(13,916,012)	(12,050,541)
Net deferred tax liabilities	—	—
Movements		
Opening balance at 1 July	12,050,541	10,720,341
Charged / (Credited) to the income statement	1,865,471	1,330,200
Closing balance at 30 June	13,916,012	12,050,541
Deferred tax liabilities to be recovered after more than 12-months	13,903,950	12,046,535
Deferred tax liabilities to be recovered within 12-months	12,062	4,006
	13,916,012	12,050,541

(f) Other tax related matters

In July 2018 the Consolidated Entity submitted objections in respect of its income tax assessments for the income years ended 30 June 2013 to 30 June 2016 inclusive. The objections relate to Research & Development Tax offsets and the treatment of Farmout Arrangements in respect of those years of income. As at 30 June 2018 the Consolidated Entity has not recognised any potential tax benefits from the objections lodged.

5. REMUNERATION OF AUDITORS

	2018 $	2017 $
The following fees were paid or payable for services provided by PwC Australia, the auditor of the Company, its related practices and non-related audit firms:		
(i) Audit and other assurance services		
Audit and review of financial statements	158,542	162,667
(ii) Taxation services		
Income Tax compliance	8,160	17,615
Other tax related services	26,259	19,622
	34,419	37,237
(iii) Other services		
Mereenie transaction due diligence	—	—
Technical accounting advice on major transactions	—	—
	—	—
Total remuneration of PwC	**192,961**	**199,904**

6. CASH AND CASH EQUIVALENTS

Cash at bank and in hand	27,222,845	5,478,140
Made up as follows:		
Corporate (a)	26,706,273	5,081,168
Joint arrangements (b)	516,572	396,972
	27,222,845	5,478,140

(a) $1,782,026 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2017: $1,421,848), including, but not limited to operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, and debt servicing.

(b) This balance relates to the Group's share of cash balances held under Joint Venture Arrangements.

Risk exposure

The Group's exposure to interest rate risk is discussed in Note 32. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of cash and cash equivalents.

7. TRADE AND OTHER RECEIVABLES

	2018 $	2017 $
Current		
Trade receivables	1,556,150	485,337
Accrued income (a)	4,121,642	3,711,267
Other receivables	57,541	25,417
Prepayments	896,309	774,195
	6,631,642	**4,996,216**

(a) Accrued income relates to the revenue recognition of oil and gas volumes delivered to respective customers but not yet invoiced.

The Group's exposure to credit and currency risks and impairment losses related to trade and other receivables is disclosed in Note 32.

8. INVENTORIES

Crude oil and natural gas	337,534	219,375
Spare parts and consumables	1,877,937	2,292,533
Drilling materials and supplies at cost	1,360,009	761,106
	3,575,480	**3,273,014**

9. PROPERTY, PLANT AND EQUIPMENT

	FREEHOLD LAND AND BUILDINGS $	PRODUCING ASSETS $	PLANT AND EQUIPMENT $	TOTAL $
Year ended 30 June 2017				
Opening net book amount	3,529,174	78,888,497	31,365,583	113,783,254
Additions	49,340	—	913,228	962,568
Changes to rehabilitation estimates	—	(225,435)	205,566	(19,869)
Disposals and write offs	—	—	(67,201)	(67,201)
Impairment	—	—	(89,013)	(89,013)
Depreciation charge	(349,297)	(2,553,914)	(4,850,169)	(7,753,380)
Closing net book amount	**3,229,217**	**76,109,148**	**27,477,994**	**106,816,359**
At 30 June 2017				
Cost	3,868,743	84,443,566	44,844,266	133,156,575
Accumulated depreciation	(639,526)	(8,334,418)	(17,366,272)	(26,340,216)
Net book amount	**3,229,217**	**76,109,148**	**27,477,994**	**106,816,359**
Year ended 30 June 2018				
Opening net book amount	3,229,217	76,109,148	27,477,994	106,816,359
Additions	—	—	4,668,165	4,668,165
Changes to rehabilitation estimates	—	379,448	611	380,059
Disposals and write offs	—	—	(19,838)	(19,838)
Depreciation charge	(350,202)	(3,657,662)	(3,983,512)	(7,991,376)
Closing net book amount	**2,879,015**	**72,830,934**	**28,143,420**	**103,853,369**
At 30 June 2018				
Cost	3,868,743	84,823,014	49,442,072	138,133,829
Accumulated depreciation	(989,728)	(11,992,080)	(21,298,652)	(34,280,460)
Net book amount	**2,879,015**	**72,830,934**	**28,143,420**	**103,853,369**

10. EXPLORATION ASSETS

	2018 $	2017 $
Acquisition costs of right to explore	**8,898,767**	**8,898,767**
Movement for the year:		
Balance at the beginning of the year	8,898,767	8,898,767
Impairment of exploration assets	—	—
Balance at the end of the year	**8,898,767**	**8,898,767**

11. INTANGIBLE ASSETS

	2018 $	2017 $
SOFTWARE		
At the beginning of the year		
Cost	379,615	358,365
Accumulated amortisation	(297,458)	(275,972)
Net book value	**82,157**	**82,393**
Movements for the year		
Opening net book amount	82,157	82,393
Additions	115,576	27,014
Disposals and write offs	—	(54)
Amortisation	(41,716)	(27,196)
Closing net book amount	**156,017**	**82,157**
At the end of the year		
Cost	495,191	379,615
Accumulated amortisation	(339,174)	(297,458)
Net book value	**156,017**	**82,157**

12. OTHER FINANCIAL ASSETS

Current		
Security deposits paid for drilling operations	**2,333,333**	—
Non-Current		
Security bonds on exploration permits and rental properties	**2,535,915**	**2,501,947**

Security bonds are provided to State or Territory governments in respect of certain performance obligations arising from awarded petroleum and mineral tenements. The bonds are typically provided as cash or as bank guarantees in favour of the State or Territory government secured by term deposits with the financial institution providing the bank guarantee.

13. GOODWILL

Goodwill arising from business combinations	**3,906,270**	**3,906,270**

Impairment tests for goodwill

Goodwill is monitored by management at the level of the operating segments and has been allocated to gas producing assets. There has been no impairment of amounts previously recognised as goodwill. Goodwill is tested for impairment on an annual basis. The recoverable amount of a Cash Generating Unit ("CGU") is determined based on value-in-use calculations which require the use of assumptions. The calculations use cash flow projections based on budgets for the next financial year as approved by management and forecasts beyond the budget based on extrapolations using estimated growth rates.

Cash flows for revenues are based on contracted gas prices with allowance for CPI increases to prices where applicable.

13. GOODWILL (CONTINUED)

The following table sets out the key assumptions for the gas producing assets value-in-use calculations:

2018	Producing Assets
Sales volumes	Contracted
Sales price (% annual growth rate)	2.5%
Operating costs (% annual growth rate)	2.5%
Pre-tax discount rate (%)	14.0%

Management has determined the values assigned to each of the above key assumptions as follows:

Assumption	Approach used to determining values
Sales volume	Natural Gas sales are based on Annual Contract Quantities for existing contracts which continue at projected firm plant capacity until 2P reserves are utilised. Crude and condensate volumes are based on projected field production, taking into account historical production and forecast reservoir decline.
Sales price	Current contracted prices escalated for CPI increases as per contracts. Some contracts contain minimum and maximum increases. Crude and condensate pricing is based on a mid-point of independent analyst forecasts of crude prices and a long-term forecast average USD exchange rate.
Operating costs	Current budgeted operating costs which are based on past performance and expectations for the future. Forecasts are inflated beyond the budget year using inflationary estimates. Other known factors are included where applicable and known with certainty.
Capital expenditure	Expected cash costs where further field capital expenditure is required in order to meet contracted and projected sales volumes.
Long term growth rate	This is the average growth rate used to extrapolate cash flows beyond the budget period. Management considers forecast inflation rates and industry trends if applicable.
Pre-tax discount rate	This rate reflects risks relating to the segment. Post-tax discount rates have been applied to discount the forecast future post-tax cash flows. The equivalent pre-tax discount rates are disclosed in the table above.

14. TRADE AND OTHER PAYABLES

	2018	2017
	$	$
Current		
Trade payables	2,287,469	2,552,400
Other payables	1,311	492
Tax related payables	634,167	—
Deposits held	150,000	—
Accruals	5,040,720	686,276
	8,113,667	**3,239,168**

Trade payables are usually non-interest bearing provided payment is made within the terms of credit. The Consolidated Entity’s exposure to liquidity and currency risks related to trade and other payables is disclosed in Note 32.

15. DEFERRED REVENUE

Proceeds received under Take-or-Pay gas sales contracts where gas is able to be taken by the customer in future periods:

	2018 $	2017 $
Current		
Proceeds received under Take-or-Pay gas sales contracts - Available to be taken within 12-months (a)	2,714,334	2,714,334
Deferred revenue under other gas sales contracts (b)	4,568,734	—
	7,283,068	**2,714,334**
Non-Current		
Proceeds received under Take-or-Pay gas sales contracts - Available to be taken after 12-months (a)	10,381,732	5,283,741
Deferred revenue under other gas sales contracts (b)	3,297,248	—
	13,678,980	**5,283,741**

(a) Take-or-Pay proceeds are taken to revenue at the earlier of physical delivery of the gas to the customer or upon forfeiture of the right to gas under the contract.

(b) In June 2018 Macquarie Bank Limited novated its rights and obligations under the First Contract Year of the MBL Gas Sale and Prepayment Agreement (refer Note 18), to Incitec Pivot Limited through a new Gas Sale Agreement. There was no cash settlement option under the novation. This resulted in an amount of $7,865,982 being transferred from Other Financial Liabilities to Deferred Revenue. Revenue will be recognised as gas is delivered to IPL.

16. INTEREST BEARING LIABILITIES

	2018 $	2017 $
(a) Interest bearing liabilities (current)[1]		
Debt facilities	3,727,338	3,859,747
	3,727,338	**3,859,747**
(b) Interest bearing liabilities (non-current)[1]		
Debt facilities	74,599,221	78,310,007
	74,599,221	**78,310,007**

[1] *Details regarding interest bearing liabilities are contained in Note 32(e).*

17. PROVISIONS

	2018			2017		
	Current	**Non-current**	**Total**	Current	Non-current	Total
	$	**$**	**$**	$	$	$
Employee entitlements (a)	2,883,557	660,179	3,543,736	3,059,075	516,369	3,575,444
Restoration and rehabilitation (b)	522,958	21,639,197	22,162,155	102,379	21,160,338	21,262,717
Joint Venture production over-lift (c)	—	3,541,059	3,541,059	—	1,712,422	1,712,422
	3,406,515	**25,840,435**	**29,246,950**	**3,161,454**	**23,389,129**	**26,550,583**

(c) The current provision for employee entitlements includes accrued short term incentive plans, all accrued annual leave and the unconditional entitlements to long service leave where employees have completed the required period of service. The amounts are presented as current, since the Consolidated Entity does not have an unconditional right to defer settlement for these obligations. However, based on past experience, the Group does not expect all employees to take the full amount of accrued leave or require payment in the next 12-months. The following amounts reflect leave that is not expected to be taken or paid within the next 12-months:

	2018	2017
	$	$
Current leave obligations expected to be settled after 12-months	778,897	706,408

(d) Provisions for future removal and restoration costs are recognised where there is a present obligation and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

(e) Under an Interim Gas Balancing Agreement with its joint venture partners, the Group has taken a higher proportion of natural gas produced from the Mereenie joint venture than its joint venture percentage entitlement. A provision has been recognised to reflect the expected additional production costs of rebalancing production entitlements between the joint venture partners from future operations.

Movements in Provisions

Movements in each class of provision during the financial year are set out below:

2018	Employee Entitlements $	Restoration & Rehabilitation $	Other $	Total $
Carrying amount at start of year	**3,575,444**	**21,262,717**	**1,712,422**	**26,550,583**
Change in provision charged to property, plant and equipment	—	380,059	—	380,059
Additional provisions charged to profit or loss	1,199,878	5,619	1,828,637	3,034,134
Reversal of previous provisions	—	—	—	—
Unwinding of discount	—	513,760	—	513,760
Amounts used during the year	(1,231,586)	—	—	(1,231,586)
Carrying amount at end of year	**3,543,736**	**22,162,155**	**3,541,059**	**29,246,950**

18. OTHER FINANCIAL LIABILITIES

	2018 $	2017 $
Current		
Lease incentive liabilities	38,600	38,600
	38,600	**38,600**
Non-Current		
Lease incentive liabilities	83,633	122,233
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	15,278,873	21,792,304
	15,362,506	**21,914,537**

(a) In June 2018 Macquarie Bank Limited novated its rights and obligations under the First Contract Year of the MBL Gas Sale and Prepayment Agreement, to Incitec Pivot Limited ("IPL"). This resulted in an amount of $7,865,982 being reclassified from Other Financial Liabilities to Deferred Revenue. The balance at 30 June 2018 represents the remaining liabilities under the Second and Third Contract Year.

19. CONTRIBUTED EQUITY

(a) Share capital

	2018 $	2017 $
707,081,966 fully paid ordinary shares (2017: 433,197,647)	197,776,488	172,301,532

Ordinary shares have no par value and the Company does not have a limited amount of authorised capital.

On a show of hands, every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote.

(b) Movements in ordinary share capital

	2018 No. of shares	2017 No. of shares	**2018 $**	2017 $
Balance at start of year	433,197,647	433,197,647	172,301,532	172,301,532
Placement of shares to institutional investors on 17 August 2017 at 10 cents per share	92,000,980	—	9,200,098	—
Shares issued pursuant to the 5 for 12 Entitlement Offer on 08 September 2017 at 10 cents per share	180,499,020	—	18,049,902	—
Capital raising costs	—	—	(1,775,044)	—
Shares issued under Employee Long Term Incentive Plans	1,384,319	—	—	—
Balance at end of year	**707,081,966**	**433,197,647**	**197,776,488**	**172,301,532**

(c) Movements in Share Options

There were no options granted or exercised during the year.

The following options over unissued ordinary shares lapsed during the year:

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted employee options	15 Nov 2017	$0.450	26,168,035
Unlisted employee options	15 Nov 2017	$0.400	365,100
Unlisted employee options	15 Nov 2017	$0.650	27,300

(d) Unissued shares under option

At year end, options over unissued ordinary shares of the Company are as follows:

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted financing options	01 Sep 2019	$0.200	30,000,000

None of the options entitle holders to participate in any share issue of the Company or any other entity.

19. CONTRIBUTED EQUITY (CONTINUED)

(e) Deferred share rights under the Long Term Incentive Plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Except in a limited number of circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year. The table below sets out the maximum number of deferred share entitlements outstanding at year end, subject to performance hurdles.

CLASS	EXPIRY DATE	PLAN YEAR COMMENCING	NUMBER OF RIGHTS
Employee LTIP rights	23 Sep 2020	1 Jul 2014	80,470
Employee LTIP rights	05 Jan 2021	1 Jul 2015	5,782,633
Employee LTIP rights	09 Feb 2021	1 Jul 2015	1,913,873
Employee LTIP rights	08 Dec 2022	1 Jul 2015	125,183
Employee LTIP rights	03 Oct 2022	1 Jul 2015	327,000
Employee LTIP rights	08 Dec 2022	1 Jul 2016	13,469,753
Employee LTIP rights	09 Feb 2022	1 Jul 2016	31,655
Employee LTIP rights	03 Oct 2022	1 Jul 2016	70,000
Employee LTIP rights	03 Oct 2022	1 Jul 2017	6,387,404
Employee LTIP rights	18 Dec 2022	1 Jul 2017	1,835,910
Employee LTIP rights	23 May 2023	1 Jul 2017	16,868
Employee LTIP rights	28 Jun 2023	1 Jul 2017	135,920
Total Deferred Share Rights on issue			**30,176,669**

1,418,146 rights were converted to shares during the year (2017: Nil) and 1,523,870 rights were cancelled during the year. The rights do not entitle the holders to participate in any share issue of the Company or any other entity.

(f) Capital risk management

The Group's objective when managing capital is to safeguard the ability to continue as a going concern to ultimately add value for shareholders through the exploitation and production of hydrocarbon resources. This is monitored through the use of cash flow forecasts. In order to maintain the capital structure, the Group may issue new shares or other equity instruments.

20. RESERVES

	2018 $	2017 $
Share options reserve	**23,463,784**	**21,841,455**
Movements:		
Balance at start of year	21,841,455	19,590,431
Share based payment costs (a)	1,622,329	2,251,024
Balance at end of year	**23,463,784**	**21,841,455**

(a) The reserve is primarily used to record the value of share based payments provided to employees and Directors as part of their remuneration and underwriters of share placements. Refer to Note 31 for further details of share based payments.

21. ACCUMULATED LOSSES

	2018 $	2017 $
Movements in accumulated losses were as follows:		
Balance at the start of year	(200,100,834)	(175,374,353)
Net loss for the year	(14,076,129)	(24,726,481)
Balance at end of year	**(214,176,963)**	**(200,100,834)**

22. LOSSES PER SHARE

(a)	**Basic loss per share (cents)**	**(2.13)**	**(5.71)**
(b)	**Diluted loss per share (cents)**	**(2.13)**	**(5.71)**
(c)	**Loss used in loss per share calculation** Loss attributed to ordinary equity holders of the Company	**(14,076,130)**	**(24,726,481)**
(d)	**Weighted average number of ordinary shares** Weighted average number of shares used as the denominator in calculating basic and diluted earnings per share	**660,637,923**	**516,313,022**

Options and Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic earnings per share. Additionally, any exercise of the options would be antidilutive as their exercise to ordinary shares would decrease the loss per share. In accordance with AASB 133, they are also excluded from the diluted loss per share calculation.

23. SEGMENT REPORTING

The Group has identified its operating segments based on the internal reports that are reviewed and used by the EMT (the chief operating decision makers) in assessing performance and in determining the allocation of resources. The following operating segments are identified by management based on the nature of the business or venture.

Producing assets

Production and sale of crude oil, natural gas and associated petroleum products from fields that are in the production phase.

Development assets

Fields under development in preparation for the sale of petroleum products. There no fields under development during the current or prior financial year.

Exploration assets

Exploration and evaluation of permit areas.

Unallocated items

Unallocated items comprise non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

Performance monitoring and evaluation

Management monitors the operating results of the operating segments separately for the purpose of making decisions about resource allocation and performance assessment.

The Consolidated Entity’s operations are wholly in one geographical location, being Australia.

23. SEGMENT REPORTING (CONTINUED)

	PRODUCING ASSETS 2018 $	EXPLORATION ASSETS 2018 $	CORPORATE ITEMS 2018 $	CONSOLIDATION 2018 $
Revenue	34,939,194	—	—	34,939,194
Cost of sales	(18,704,042)	—	—	(18,704,042)
Gross profit	16,235,152	—	—	16,235,152
Other income	—	504,415	550,769	1,055,184
Share based employee benefits	—	—	(1,622,329)	(1,622,329)
General and administrative expenses	—	—	(595,925)	(595,925)
Employee benefits and associated costs	—	—	(4,061,759)	(4,061,759)
Other operating expenses	—	—	—	—
EBITDAX	**16,235,152**	**504,415**	**(5,729,244)**	**11,010,323**
Depreciation and amortisation	(7,745,236)	—	(287,856)	(8,033,092)
Exploration expenditure	(6,027,109)	(2,762,943)	—	(8,790,052)
Finance costs	(7,326,850)	(28,223)	(493,804)	(7,848,877)
Restatement of financial liability (b)	(414,431)	—	—	(414,431)
Loss before income tax	**(5,278,474)**	**(2,286,751)**	**(6,510,904)**	**(14,076,129)**
Taxes	—	—	—	—
Loss for the year	**(5,278,474)**	**(2,286,751)**	**(6,510,904)**	**(14,076,129)**
Segment assets	**121,601,949**	**12,625,994**	**24,885,695**	**159,113,638**
Segment liabilities	**(136,584,039)**	**(2,828,327)**	**(12,637,964)**	**(152,050,330)**
Capital expenditure				
Property, plant and equipment	**4,433,420**	—	234,745	4,668,165
Total capital expenditure	**4,433,420**	**—**	**234,745**	**4,668,165**

23. SEGMENT REPORTING (CONTINUED)

	PRODUCING ASSETS 2017 $	EXPLORATION ASSETS 2017 $	CORPORATE ITEMS 2017 $	CONSOLIDATION 2017 $
Revenue	24,794,145	—	—	24,794,145
Cost of sales	(15,701,690)	—	—	(15,701,690)
Gross profit	9,092,455	—	—	9,092,455
Other income (a)	120,017	2,315,475	678,546	3,114,038
Share based employee benefits	—	—	(2,251,024)	(2,251,024)
General and administrative expenses	—	—	(1,946,659)	(1,946,659)
Employee benefits and associated costs	—	—	(5,658,990)	(5,658,990)
Other operating expenses	—	—	—	—
EBITDAX	**9,212,472**	**2,315,475**	**(9,178,127)**	**2,349,820**
Depreciation and amortisation	(7,488,544)	(8,087)	(283,945)	(7,780,576)
Exploration expenditure	(471,532)	(1,429,850)	—	(1,901,382)
Finance costs	(7,265,784)	(15,749)	(530,538)	(7,812,071)
Restatement of financial liability (b)	(9,493,259)	—	—	(9,493,259)
Impairment expense	—	(89,013)	—	(89,013)
Loss before income tax	**(15,506,647)**	**772,776**	**(9,992,610)**	**(24,726,481)**
Taxes	—	—	—	—
Loss for the year	**(15,506,647)**	**772,776**	**(9,992,610)**	**(24,726,481)**
Segment assets	**119,923,785**	**11,408,488**	**4,620,597**	**135,952,870**
Segment liabilities	**(127,314,178)**	**(1,659,886)**	**(12,936,653)**	**(141,910,717)**
Capital expenditure				
Property, plant and equipment	599,361	—	363,207	962,568
Total capital expenditure	**599,361**	**—**	**363,207**	**962,568**

(a) Under the terms of the Southern Georgina Farmout Agreement between Merlin Energy Pty Ltd ("Merlin") and Total GLNG Australia ("Total"), Total were required to pay for the first 80% of Stage 1 farmin expenditure and Merlin Energy were required to pay for the last 20%. In February 2017 Total elected not to proceed to Stage 2 of the Farmin and to withdraw from the Joint Venture. The Deed of Assignment, Assumption and Transfer of Total's interests included releasing Merlin from all amounts accrued up to the date of withdrawal by Total. The extinguishment of the liability of $2,017,000 is recorded as other income for 2017 under the Exploration segment.

(b) In 2016 the Group entered into a Gas Sale and Prepayment Agreement with Macquarie Group, to commence following completion of the Northern Gas Pipeline. Under the agreement Macquarie may elect to receive a financial settlement in lieu of taking physical delivery of the gas. The financial settlement amount, if so elected, is dependent on the ex-field price received by the Group under any new gas sales agreements from the designated production area. As a result of the Group signing a new gas sales agreement during the 2017 year, under the applicable accounting standards, it was necessary to re-assess the value of the financial settlement option under the Gas Sale and Prepayment Agreement. This resulted in an increase in the recorded financial liability of $9,493,259 and an expense for the same amount recorded in the 2017 year. The financial liability is reviewed regularly for updates to pricing and timing assumptions. This resulted in an expense of $414,431 in the 2018 financial year. A financial settlement would be paid out of the proceeds of gas sold under the new gas sales agreements. See also Notes 3 and 18.

23. SEGMENT REPORTING (CONTINUED)

	2018 $	2017 $
Revenue from external customers by geographical location of production		
Australia	34,939,194	24,794,145
Non-current assets by geographical location		
Australia	119,350,338	122,205,500

Major Customers

Customers with revenue exceeding 10% of the group's total oil and gas sales revenue are shown below.

	2018 $	% of Sales Revenue	2017 $	% of Sales Revenue
Largest customer	8,665,876	25%	7,600,694	31%
Second largest customer	6,948,934	20%	6,398,720	26%
Third largest customer	6,314,195	18%	5,632,967	23%
Fourth largest customer	5,250,226	15%	—	—
Fifth largest customer	4,008,261	11%	—	—

24. PARENT ENTITY INFORMATION

(a) Summary financial information

The individual financial summary statements for the Parent Entity show the following aggregate amounts:

	2018 $	2017 $
Statement of financial position		
Current assets	28,495,981	5,999,204
Non-current assets	9,075,508	9,131,712
Total assets	37,571,489	15,130,916
Current liabilities	(24,299,693)	(7,656,045)
Total liabilities	(25,257,763)	(8,503,576)
Net assets	**12,313,726**	**6,627,340**
Shareholders' equity		
Issued capital	197,776,487	172,301,532
Reserves	23,463,783	21,841,455
Accumulated losses	(208,926,544)	(187,515,647)
Total equity	**12,313,726**	**6,627,340**
Loss for the year	**(21,410,897)**	**(8,769,073)**
Total comprehensive loss	**(21,410,897)**	**(8,769,073)**

24. PARENT ENTITY INFORMATION (CONTINUED)

(b) Guarantees entered into by the Parent Entity

Guarantees have been provided by the Parent Entity to subsidiaries arising out of the course of ordinary operations.

A Macquarie Loan Facility exists under which the parent and non-borrowing subsidiaries have provided guarantees to Macquarie Bank in relation to the repayment of monies owing and other performance related obligations of the Borrower typical for a borrowing of this nature. Monies received through the operation of the Palm Valley, Dingo and Mereenie fields are subject to a proceeds account and can be distributed to the parent as available when no default exists. Revenues resulting from operations outside of these assets (such as Surprise) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

(c) Commitments of the Parent Entity

Operating lease commitments of the Parent Entity are set out in Note 30(c).

25. RELATED PARTY TRANSACTIONS

(a) Parent Entity

The parent entity is Central Petroleum Limited.

(b) Subsidiaries

The consolidated financial statements include the financial statements of Central Petroleum Limited and the subsidiaries listed in the following table:

NAME OF ENTITY	PLACE OF INCORPORATION	CLASS OF SHARES	EQUITY HOLDING **2018** %	EQUITY HOLDING 2017 %
Merlin Energy Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Projects Pty Ltd (formerly Merlin West Pty Ltd)	Western Australia	Ordinary	100	100
Helium Australia Pty Ltd	Victoria	Ordinary	100	100
Ordiv Petroleum Pty Ltd	Western Australia	Ordinary	100	100
Frontier Oil & Gas Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Eastern Pty Ltd (formerly Central Green Pty Ltd)	Western Australia	Ordinary	100	100
Central Geothermal Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Services Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum PVD Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum (NT) Pty Ltd	Queensland	Ordinary	100	100
Jarl Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Unit Trust	N/A	Units	100	100
Central Petroleum WS (NO 1) Pty Ltd	Queensland	Ordinary	100	Nil
Central Petroleum WS (NO 2) Pty Ltd	Queensland	Ordinary	100	Nil

(c) Key management personnel

Disclosures relating to key management personnel are set out in Note 26.

26. KEY MANAGEMENT PERSONNEL

(a) Key management personnel compensation

	2018 $	2017 $
Short-term employee benefits	2,561,475	2,373,766
Post-employment benefits	139,774	142,141
Termination benefits	—	—
Long-term benefits	59,756	46,583
Share based payments	1,097,869	1,798,104
	3,858,874	**4,360,594**

Detailed remuneration disclosures are provided in the remuneration report on pages 23 to 32.

(b) Equity instrument disclosures relating to key management personnel

(i) Options provided as remuneration and shares issued on exercise of such options

No options were provided as remuneration and no shares were issued on the exercise of options during the current or prior financial year.

(ii) Option holdings

There were no options on issue to key management personnel at 30 June 2018. The number of options over ordinary shares in the Company held during the financial year by each Director of Central Petroleum Limited and other key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

		BALANCE AT START OF YEAR	GRANTED AS COMPENSATION	EXERCISED	EXPIRED OR FOREITED	HELD AT DATE OF DEPARTURE	BALANCE AT END OF YEAR	VESTED EXERCISABLE	UNVESTED
Non-Executive Directors									
Wrixon Gasteen	2018	—	—	—	—	N/A	—	—	—
	2017	666,666	—	—	(666,666)	N/A	—	—	—
Executive Directors and Other Key Management Personnel									
Richard Cottee[1]	2018	24,900,773	—	—	(24,900,773)	N/A	—	—	—
	2017	24,900,773	—	—	—	N/A	24,900,773	—	24,900,773
Leon Devaney	2018	—	—	—	—	N/A	—	—	—
	2017	504,000	—	—	(504,000)	N/A	—	—	—
Michael Herrington	2018	—	—	—	—	N/A	—	—	—
	2017	1,950,000	—	—	(1,950,000)	N/A	—	—	—
Daniel White	2018	—	—	—	—	N/A	—	—	—
	2017	760,000	—	—	(760,000)	N/A	—	—	—

[1] *On 8 August 2012, 34,584,407 unlisted options exercisable at $0.45 on or before 15 November 2015 and 15 November 2017 were issued to FEP, a company in which Richard Cottee has a 50% beneficial interest. Remaining options expired on 15 November 2017.*

26. KEY MANAGEMENT PERSONNEL (CONTINUED)

(iii) Deferred shares – long term incentive plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Except in limited circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year.

The maximum number of rights to ordinary shares in the Company under the long term incentive plan held during the financial year by other key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

		RIGHTS HELD AT START OF YEAR	MAXIMUM NO. GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	HELD AT DATE OF DEPARTURE	CONVERTED TO SHARES	RIGHTS HELD AT END OF YEAR)
Executive Directors and Other Key Management Personnel							
Richard Cottee	2018	5,307,887	1,854,229	(104,675)	N/A	(104,675)	6,952,766
	2017	2,104,904	3,202,983	—	N/A	—	5,307,887
Leon Devaney	2018	2,373,104	917,339	(152,643)	N/A	(152,642)	2,985,158
	2017	1,061,571	1,311,533	—	N/A	—	2,373,104
Ross Evans[2]	2018	N/A	—	—	N/A	—	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A
Michael Herrington	2018	2,886,237	931,057	(218,397)	N/A	(218,396)	3,380,501
	2017	930,000	1,956,237	—	N/A	—	2,886,237
Robin Polson[1]	2018	N/A	—	—	N/A	—	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A
Daniel White	2018	2,389,666	767,966	(180,824)	N/A	(180,823)	2,795,985
	2017	1,100,000	1,289,666	—	N/A	—	2,389,666

[1] *Robin Polson commenced 1 May 2018*
[2] *Ross Evans commenced 1 June 2018*

26. KEY MANAGEMENT PERSONNEL (CONTINUED)

(iv) Share holdings

The number of shares in the Company held during the financial year by each Director of Central Petroleum Limited and other key management personnel of the Consolidated Entity, including their personally related parties, are set out below. There were no shares granted as compensation during the year.

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF RIGHTS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Wrixon Gasteen	2018	136,473	—	156,864	—	—	N/A	293,337
	2017	136,473	—	—	—	—	N/A	136,473
Robert Hubbard[1]	2018	298,947	—	365,667	—	—	664,614	N/A
	2017	298,947	—	—	—	—	N/A	298,947
Martin Kriewaldt[2]	2018	N/A	200,000	900,000	—	—	N/A	1,100,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Peter Moore	2018	—	—	265,000	—	—	N/A	265,000
	2017	—	—	—	—	—	N/A	—
Sarah Ryan[2]	2018	N/A	—	105,000	—	—	N/A	105,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Timothy Woodall[3]	2018	N/A	1,000,000	500,000	—	—	N/A	1,500,000
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Executive Directors and Other Key Management Personnel								
Richard Cottee	2018	571,829	—	216,929	104,675	(3,500)[4]	N/A	889,933
	2017	632,438	—	—	—	(60,609)[4]	N/A	571,829
Leon Devaney	2018	210,000	—	266,380	152,642	—	N/A	629,022
	2017	210,000	—	—	—	—	N/A	210,000
Ross Evans[6]	2018	N/A	—	—	—	—	N/A	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Michael Herrington	2018	250,000	—	104,168	218,396	—	N/A	572,564
	2017	250,000	—	—	—	—	N/A	250,000
Robin Polson[5]	2018	N/A	—	—	—	—	N/A	—
	2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Daniel White	2018	288,000	—	160,000	180,823	—	N/A	628,823
	2017	288,000	—	—	—	—	N/A	288,000

1 *Robert Hubbard retired 14 May 2018*
2 *Martin Kriewaldt and Sarah Ryan were appointed Directors 23 October 2017*
3 *Timothy Woodall was appointed Director 20 December 2017*
4 *Shares held by members of Mr Cottee's family and no longer considered under Mr Cottee's control have been removed from this table.*
5 *Robin Polson commenced 1 May 2018*
6 *Ross Evans commenced 1 June 2018*

(c) Other transactions with key management personnel

There were no other transactions with Key Management Personnel

27. RECONCILIATION OF LOSS AFTER INCOME TAX TO NET CASH OUTFLOW FROM OPERATING ACTIVITIES

	2018 $	2017 $
Loss after income tax	(14,076,129)	(24,726,481)
Adjustments for:		
Depreciation and amortisation	8,033,092	7,780,576
(Profit)/Loss on disposal of assets	(13,799)	47,665
Profit on disposal of exploration permits	(280,000)	(280,000)
Share-based payments	1,622,329	2,251,024
Impairment expense	—	89,013
Restatement of financial liabilities	414,431	9,493,259
Financing costs and interest (non-cash)	1,347,819	1,019,499
Changes in assets and liabilities relating to operating activities:		
(Increase) / Decrease in trade and other receivables	(1,634,805)	(1,208,938)
Decrease in inventories	(302,466)	319,547
Decrease in other financial assets	—	17,785
Increase/(Decrease) in trade and other payables	2,687,060	(1,893,483)
Increase in deferred revenue	5,097,991	4,030,668
Increase in financial liabilities	(38,600)	160,833
Increase in provisions	2,316,307	2,665,032
Net cash inflow/(outflow) from operations	**5,173,230**	**(234,001)**

28. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

Non-cash interest relating to Other Financial Liabilities amounted to $938,119 (2017: $533,774). Additionally, non-cash revaluation expense amounted to $414,431 (2017: $9,493,259). Refer Note 3(a).

Due to a novation of rights and obligations under the MBL Gas Sale and Prepayment Agreement from MBL to IPL in respect of the First Contract Year, an amount of $7,865,982 was transferred to Deferred Revenue, reflecting the removal of the cash settlement option for the First contract year. (Refer Note 15 and Note 18 for further details).

(b) Net debt reconciliation

This section provides an analysis of those liabilities for which cash flows have been, or will be classified as financing activities in the statement of cash flows. Cash balances included as current assets on the Statement of Financial Position are included as the Group considers these to form part of its net debt.

28. CASH FLOW INFORMATION (CONTINUED)

(b) Net debt reconciliation (continued)

Net debt

	2018 $	2017 $
Cash and cash equivalents	27,222,845	5,478,140
Borrowings – repayable within one year	(3,727,338)	(3,606,853)
Borrowings – repayable after one year	(74,599,221)	(78,310,007)
Net debt	**(51,103,714)**	**(76,438,720)**
Cash	27,222,845	5,478,140
Gross debt – variable interest rates	(78,326,559)	(81,916,860)
Net debt	**(51,103,714)**	**(76,438,720)**

Movement in Net Debt

	Other Assets	Liabilities from financing activities		
	Cash $	Borrowings due within 1 year $	Borrowings due after 1 year $	Total $
Net debt 1 July 2016	**15,115,699**	**(3,514,275)**	**(81,916,860)**	**(70,315,436)**
Cash flows	(9,637,559)	4,000,000	—	(5,637,559)
Reclassification of category	—	(3,606,853)	3,606,853	—
Other non-cash movements	—	(485,725)	—	(485,725)
Net debt 30 June 2017	**5,478,140**	**(3,606,853)**	**(78,310,007)**	**(76,438,720)**
Cash flows	21,744,705	4,000,000	—	25,744,705
Reclassification of category	—	(3,710,786)	3,710,786	—
Other non-cash movements	—	(409,699)	—	(409,699)
Net debt 30 June 2018	**27,222,845**	**(3,727,338)**	**(74,599,221)**	**(51,103,714)**

29. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2018 in respect of certain joint arrangement payments. As partial consideration under the terms of the purchase agreement for EPs 105, 106 and 107, there is a requirement to pay the vendor the sum of $1,000,000 (2017: $1,000,000) within 12-months following the commencement of any future commercial production from the permits. No commercial production is currently forecast from these permits.

(ii) Palm Valley Gas Field Gas Price Bonus

Under the Share Sale and Purchase Deed entered into with Magellan Petroleum Australia Pty Limited ("Magellan") in February 2014 for the purchase of Palm Valley and Dingo gas fields and related assets, Central Petroleum Limited is obligated to pay Magellan a Gas Price Bonus where the weighted average price of gas sold from the Palm Valley gas field during a Contract Year exceeds certain price hurdles during a period of 15-years following Completion of the Agreement. The Gas Price Bonus Amount is calculated as 25% of the difference between the weighted average price of gas actually sold (excluding GST and other costs) in a Contract Year and the gas price bonus hurdle applicable to that Contract Year (after adjusting for CPI), multiplied by the actual volume of gas originating and sold from the Palm Valley gas field.

29. CONTINGENCIES (CONTINUED)

(a) Contingent liabilities (continued)

(ii) Palm Valley Gas Field Gas Price Bonus (continued)

The weighted average price of gas sold from the Palm Valley gas field is currently below the Gas Price Bonus hurdle price and therefore no gas price bonus is payable at this time. Based on current reserves and production profiles for the Palm Valley Gas Field, and current Northern Territory gas market conditions, we do not anticipate paying a gas price bonus over the relevant term and have therefore ascribed a $nil value to this contingent liability. Should access to additional reserves and significantly higher priced markets eventuate, this contingent liability will be revisited. Importantly, any future payment of the Gas Price Bonus would only occur where sales and revenues from the Palm Valley gas field materially exceed our acquisition assumptions.

(iii) Litigation

The Company has been sued in litigation filed in the District Court of Harris County, located in Houston, Texas, by Geoscience Resource Recovery, LLC ("GRR") in respect of a farm-in deal negotiated between the Perth office of Total S.A. and the Company when it was headquartered in Perth. In the lawsuit, GRR alleges that in February 2012, the Company agreed to pay GRR a certain commission if the Company entered into a farm-in agreement with a farminee brought to it by GRR. GRR alleges that it introduced the Company to Total S.A. and because the Company subsequently entered into a farm-in agreement with Total S.A., the Company is obligated to pay GRR the commission. The Company has denied any liability and has also challenged the jurisdiction of the Texas court. The trial court denied the Company's objection to the court's jurisdiction and Company's appeal to the Court of Appeals from that order was not successful. The Company, however, has filed a Petition for Review with the Supreme Court of Texas, and the Court recently requested further briefing on the issue.

The Company also filed proceedings in the Supreme Court of Queensland against GRR seeking, among other things, declarations, that the Company did not enter into and is not bound by an alleged agreement to pay GRR certain fees, and that the Company is not liable to GRR for a fee or any other sum in relation to the farm-in deal. GRR opposed jurisdiction of the Supreme Court of Queensland. GRR's application was dismissed in the Company's favour in October 2017. GRR appealed the decision which appeal was dismissed in the Company's favour on 14 September 2018.

(iv) In July 2018 the group entered into an Amending Deed with Macquarie Mereenie Pty Limited to amend the Mereenie Joint Operating Agreement effective from 22 June 2018, whereby Central Petroleum will fund any over expenditures arising from the Mereenie Plant expansion project in excess of the project authorised amount plus $1 million.

Current project forecasts indicate the project costs will be within the authorised amount and therefore Central ascribes no value to this contingent liability at the date of this report.

30. COMMITMENTS

	2018 $	2017 $
(a) Capital commitments		
The Consolidated Entity has the following capital expenditure commitments:		
The following amounts are due:		
Within one year	1,675,020	—
Later than one year but not later than three years	—	—
Later than three years but not later than five years	—	—
	1,675,020	—

(b) Exploration commitments

The Consolidated Entity has the following minimum exploration expenditure commitments:		
The following amounts are due:		
Within one year	14,155,000	4,630,000
Later than one year but not later than three years	13,325,000	25,180,000
Later than three years but not later than five years	11,050,000	2,400,000
	38,530,000	32,210,000

30. COMMITMENTS (CONTINUED)

(b) Exploration commitments (continued)

These commitments may be varied in the future as a result of renegotiations of the terms of exploration permits. In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties or relinquish (whole or part of the permit) and, as a result, obligations may be reduced or extinguished.

(c) Operating lease commitments

The Consolidated Entity through its parent entity, Central Petroleum Limited, has non-cancellable operating leases for office premises and accommodation in Alice Springs and Brisbane. The leases have varying terms, escalation clauses and renewal rights.

Commitments for minimum lease payments in relation to non-cancellable operating leases are payable as follows:

Within one year	560,413	465,421
Later than one year but not later than five years	1,221,665	1,404,222
	1,782,078	**1,869,643**

31. SHARE BASED PAYMENTS

(a) Employee options

An Incentive Option Scheme operates to provide incentives for employees. Participation in the plan is at the Board's discretion; however, the plan is open to all employees and Directors of the Company.

At the discretion of the Company, performance criteria may or may not be established in respect of options that vest under the Incentive Option Scheme. Options are granted for no consideration. Options that have been granted to date to employees, excluding Directors, have contained service conditions in respect of their vesting. Options have vested progressively from grant date to, in some cases, an employee's third anniversary. As of the date of this report no options issued under the Incentive Option Scheme have contained any performance criteria in respect of their vesting.

There are no rules imposing a restriction on removing the 'at risk' aspect of options granted to employees or Directors. One ordinary share is issued upon exercise of one option.

Set out below are summaries of options that have been granted to Directors and employees.

EXPIRY DATE	EXERCISE PRICE	BALANCE AT START OF THE YEAR	GRANTED DURING THE YEAR	EXERCISED DURING THE YEAR	EXPIRED OR FORFEITED DURING THE YEAR	BALANCE AT END OF THE YEAR	VESTED AND EXERCISABLE AT THE END OF THE YEAR
		No.	No.	No.	No.	No.	$
2018							
15 Nov 2017	$0.450	24,900,773	—	—	(24,900,773)	—	—
15 Nov 2017	$0.450	1,466,667	—	—	(1,466,667)	—	—
15 Nov 2017	$0.450	1,800,595	—	—	(1,800,595)	—	—
15 Nov 2017	$0.400	365,100	—	—	(365,100)	—	—
15 Nov 2017	$0.650	27,300	—	—	(27,300)	—	—
Totals		**28,560,435**	**—**	**—**	**(28,560,435)**	**—**	**—**
Weighted average exercise price		$0.45	—	—	$0.45	—	—
Weighted average remaining contractual life (years) at the end of the year						—	

31. SHARE BASED PAYMENTS (CONTINUED)

(a) Employee options (continued)

EXPIRY DATE	EXERCISE PRICE	BALANCE AT START OF THE YEAR	GRANTED DURING THE YEAR	EXERCISED DURING THE YEAR	EXPIRED OR FORFEITED DURING THE YEAR	BALANCE AT END OF THE YEAR	VESTED AND EXERCISABLE AT THE END OF THE YEAR
		No.	No.	No.	No.	No.	$
2017							
20 Jul 2016	$0.550	669,334	—	—	(669,334)	—	—
19 Aug 2016	$0.575	400,000	—	—	(400,000)	—	—
30 Aug 2016	$0.575	600,000	—	—	(600,000)	—	—
15 Nov2016	$0.475	2,318,668	—	—	(2,318,668)	—	—
30 Nov 2016	$0.475	400,000	—	—	(400,000)	—	—
15 Nov 2017	$0.450	24,900,773	—	—	—	24,900,773	—
15 Nov 2017	$0.450	2,733,335	—	—	(1,266,668)	1,466,667	—
15 Nov 2017	$0.475	2,799,350	—	—	(2,799,350)	—	—
15 Nov 2017	$0.450	2,429,068	430,827	—	(1,059,300)	1,800,595	—
15 Nov 2017	$0.400	782,525	—	—	(417,425)	365,100	—
15 Nov 2017	$0.410	234,000	—	—	(234,000)	—	—
15 Nov 2017	$0.650	393,900	—	—	(366,600)	27,300	—
Totals		**38,660,953**	**430,827**	—	**(10,531,345)**	**28,560,435**	—
Weighted average exercise price		$0.46	$0.45	—	$0.49	$0.45	—
Weighted average remaining contractual life (years) at the end of the year						0.38	

(b) Employee options granted during the year

No options were granted during the year ended 30 June 2018.

The following options were granted during the year ended 30 June 2017:

GRANT DATE	EXPIRY DATE	NUMBER OF OPTIONS	AVERAGE FAIR VALUE PER OPTION	EXERCISE PRICE	PRICE OF SHARES ON GRANT DATE	ESTIMATED VOLATILITY*	RISK FREE INTEREST RATE	DIVIDEND YIELD
2017								
07 Mar 2017	15 Nov 2017	430,827*	$Nil	$0.450	$0.150	80-90%	1.84%	0.0%

* *Issued to former employees under the 2012 Employee Share Option Plan. Options contain a vesting share price hurdle of $1.45 per share*

(c) Deferred shares — Long Term Incentive Plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period which three years is commencing from the start of each plan year. Except in limited circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

31. SHARE BASED PAYMENTS (CONTINUED)

(c) Deferred shares — Long Term Incentive Plan (continued)

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year. Share based payment expense for the year includes amounts expensed in respect of the following number of rights either granted or expected to be granted:

GRANT DATE	PLAN YEAR END	BALANCE AT START OF YEAR	NUMBER OF RIGHTS GRANTED	AVERAGE FAIR VALUE PER OPTION	EXERCISED DURING THE YEAR	CANCELLED OR FORFEITED	BALANCE AT END OF YEAR
2018							
27 Jun 2018	30 June 2018	—	135,920	$0.102	—	—	135,920
16 May 2018	30 June 2018	—	6,562	$0.126	—	—	6,562
16 May 2018	30 June 2018	—	10,306	$0.175	—	—	10,306
29 Nov 2017	30 June 2018	—	1,835,910	$0.055	—	—	1,835,910
29 Nov 2017	30 June 2015	—	18,319	$0.084	(9,159)	(9,160)	—
29 Sep 2017	30 June 2015	—	239,556	$0.097	(109,776)	(122,739)	7,041
01 Sep 2017	30 June 2018	—	6,124,904	$0.081	—	—	6,124,904
01 Sep 2017	30 June 2018	—	281,250	$0.115	—	(18,750)	262,500
01 Sep 2017	30 June 2017	—	70,000	$0.082	—	—	70,000
01 Sep 2017	30 June 2016	—	327,000	$0.056	—	—	327,000
24 Jan 2017	30 June 2017	31,655	—	$0.190	—	(6,331)	25,324
16 Nov 2016	30 June 2017	6,050,315	—	$0.151	—	—	6,050,315
20 Oct 2016	30 June 2017	7,053,384	—	$0.106	—	—	7,053,384
20 Oct 2016	30 June 2017	405,718	—	$0.135	—	(33,333)	372,385
20 Oct 2016	30 June 2016	28,761	—	$0.135	—	(10,244)	18,517
20 Oct 2016	30 June 2016	106,666	—	$0.087	—	—	106,666
22 Dec 2015	30 June 2016	1,913,873	—	$0.123	—	—	1,913,873
03 Dec 2015	30 June 2016	6,063	—	$0.165	—	—	6,063
09 Nov 2015	30 June 2016	521,749	—	$0.184	—	(6,666)	515,083
14 Oct 2015	30 June 2016	5,261,487	—	$0.147	—	—	5,261,487
22 Dec 2015	30 June 2015	191,031	—	$0.085	(95,516)	(95,515)	—
17 Jun 2015	30 June 2015	2,498,256	—	$0.074	(1,203,695)	(1,221,132)	73,429
Totals		**24,068,958**	**9,049,727**		**(1,418,146)**	**(1,523,870)**	**30,176,669**
2017							
24 Jan 2017	30 June 2017	—	31,655	$0.190	—	—	31,655
16 Nov 2016	30 June 2017	—	6,050,315	$0.151	—	—	6,050,315
20 Oct 2016	30 June 2017	—	7,160,584	$0.106	—	(107,200)	7,053,384
20 Oct 2016	30 June 2017	—	449,218	$0.135	—	(43,500)	405,718
20 Oct 2016	30 June 2016	—	33,052	$0.135	—	(4,291)	28,761
20 Oct 2016	30 June 2016	—	106,666	$0.087	—	—	106,666
22 Dec 2015	30 June 2016	1,913,873	—	$0.123	—	—	1,913,873
03 Dec 2015	30 June 2016	6,063	—	$0.165	—	—	6,063
09 Nov 2015	30 June 2016	528,415	—	$0.184	—	(6,666)	521,749
14 Oct 2015	30 June 2016	5,344,370	—	$0.147	—	(82,883)	5,261,487
22 Dec 2015	30 June 2015	191,031	—	$0.085	—	—	191,031
17 Jun 2015	30 June 2015	2,537,112	—	$0.074	—	(38,856)	2,498,256
Totals		**10,520,864**	**13,831,490**		**—**	**(283,396)**	**24,068,958**

31. SHARE BASED PAYMENTS (CONTINUED)

(d) Expenses arising from share-based payment transactions

Total expenses arising from share-based transactions recognised during the year were:

	2018 **$**	2017 $
Options and rights issued to Directors and employees	1,622,329	2,251,024

32. FINANCIAL RISK MANAGEMENT

The Consolidated Entity's principal financial instruments are cash and short-term deposits. The Consolidated Entity also has other financial assets and liabilities such as trade receivables, trade payables and borrowings, which arise directly from its operations. The Consolidated Entity's risk management objective with regard to financial instruments and other financial assets include gaining interest income and the policy is to do so with a minimum of risk.

(a) Credit Risk

The credit risk on financial assets of the Consolidated Entity which have been recognised in the statement of financial position is generally the carrying amount, net of any provision for doubtful debts. The Consolidated Entity trades only with recognised banks and large customers where the credit risk is considered minimal.

Customer credit risk is managed in accordance with the Group's established policy, procedures and controls. Outstanding customer receivables are regularly monitored and relate to the Groups' customers for which there is no history of credit risk or overdue payments. An impairment analysis is performed at each reporting date on an individual basis for the major customers.

The aging of the Consolidated Entity's receivables at reporting date was:

TRADE AND OTHER RECEIVABLES	GROSS		IMPAIRMENT	
	2018 **$**	2017 $	**2018** **$**	2017 $
Past due: 0-30 days	5,735,333	4,222,021	—	—
Past due: 31-150 days	—	—	—	—
Past due: 151-365 days	—	—	—	—
	5,735,333	**4,222,021**	—	—

Based on historic default rates, the Consolidated Entity believes that no impairment allowance is necessary in respect of receivables past due over 30 days.

The receivables at 30 June 2018 relate predominantly to the oil and gas sales from Mereenie and gas sales from the Dingo field. 100% of trade and other receivables have been received to date.

Credit risk also arises in relation to financial guarantees given to certain parties (refer Note 24(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific Board approval.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Liquidity Risk

The following are the contractual maturities of financial assets and liabilities:

2018	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	27,222,845	—	—	—	27,222,845
Trade and other receivables	5,735,333	—	—	—	5,735,333
Other financial assets	2,333,333	—	2,535,915	—	4,869,248
	35,291,511	**—**	**2,535,915**	**—**	**37,827,426**
Financial Liabilities					
Trade and other payables	(8,113,667)	—	—	—	(8,113,667)
Interest bearing liabilities	(1,858,626)	(1,868,712)	(74,599,221)	—	(78,326,559)
Other financial liabilities	(19,300)	(19,300)	(15,362,506)	—	(15,401,106)
	(9,991,593)	**(1,888,012)**	**(89,961,727)**	**—**	**(101,841,332)**

2017	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	5,478,140	—	—	—	5,478,140
Trade and other receivables	4,222,021	—	—	—	4,222,021
Other financial assets	—	—	2,501,947	—	2,501,947
	9,700,161	**—**	**2,501,947**	**—**	**12,202,108**
Financial Liabilities					
Trade and other payables	(3,239,168)	—	—	—	(3,239,168)
Interest bearing liabilities	(2,213,743)	(1,646,004)	(78,310,007)	—	(82,169,754)
Other financial liabilities	(19,300)	(19,300)	(21,646,784)	(267,753)	(21,953,137)
	(5,472,211)	**(1,665,304)**	**(99,956,791)**	**(267,753)**	**(107,362,059)**

Prudent liquidity risk management implies maintaining sufficient cash and marketable securities and the availability of funding. Management monitors rolling forecasts of the Group's liquidity reserve (comprising the undrawn borrowing facilities below) and cash and cash equivalents (Note 6) on the basis of expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Board of Directors. In addition, the Group's liquidity management policy involves projecting cash flows, monitoring balance sheet liquidity ratios against internal and external regulatory requirements and maintaining debt financing plans.

The Group manages its exposure to key financial risks primarily through supervision by the Audit and Risk Committees. The primary function of these Committees is to assist the Board to fulfil its responsibility to ensure that the Group's internal control framework is effective and efficient.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Interest Rate Risk

The Consolidated Entity's exposure to interest rate risk, which is the risk that a financial instrument's value will fluctuate as a result of changes in market interest rates and the effective weighted average interest rates on classes of financial assets and financial liabilities, is as follows:

	WEIGHTED AVERAGE EFFECTIVE INTEREST RATE		FLOATING INTEREST RATE		FIXED INTEREST		NON-BEARING INTEREST		TOTAL	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
	%	%	**$**	$	**$**	$	**$**	$	**$**	$
Financial Assets:										
Cash and cash equivalents	1.7	1.1	27,222,845	5,478,140	—	—	—	—	27,222,845	5,478,140
Trade and other receivables	—	—	—	—	—	—	5,735,333	4,222,021	5,735,333	4,222,021
Other financial assets	1.2	1.1	—	—	3,495,930	1,233,410	1,373,318	1,268,537	4,869,248	2,501,947
			27,222,845	**5,478,140**	**3,495,930**	**1,233,410**	**7,108,651**	**5,490,558**	**37,827,426**	**12,202,108**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(8,113,667)	(3,239,168)	(8,113,667)	(3,239,168)
Interest bearing liabilities	7.7	7.4	(78,326,559)	(81,916,861)	—	(252,893)	—	—	(78,326,559)	(82,169,754)
Other financial liabilities	—	—	—	—	—	—	(15,401,106)	(21,953,137)	(15,401,106)	(21,953,137)
			(78,326,559)	**(81,916,861)**	**—**	**(252,893)**	**(23,514,773)**	**(25,192,305)**	**(101,841,332)**	**(107,362,059)**
Net Financial Assets / (Liabilities)			**(51,103,714)**	**(76,438,721)**	**3,495,930**	**980,517**	**(16,406,122)**	**(19,701,747)**	**(64,013,906)**	**(95,159,951)**

Interest Rate Sensitivity

A sensitivity of 10% has been selected as this is considered reasonable given the current level of both short term and long term interest rates. A 10% movement in interest rates at the reporting date would have increased (decreased) equity and profit and loss by the amounts shown below based on the average amount of interest bearing financial instruments held. This analysis assumes that all other variables remain constant.

The analysis is performed only on those financial assets and liabilities with floating interest rates and is prepared on the same basis as for 2017.

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2018				
Cash and cash equivalents	46,419	(46,419)	—	—
Interest bearing liabilities	(604,182)	604,182	—	—
2017				
Cash and cash equivalents	6,210	(6,210)	—	—
Interest bearing liabilities	(603,045)	603,045	—	—

These movements would not have any impact on equity other than retained earnings.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(d) Commodity Risk

Gas sales are made under long term contracts and as such do not contain any commodity risk. The Consolidated Entity is exposed to commodity price fluctuations in respect of crude oil sales. The Board's current policy is not to hedge crude oil sales. The Board will continue to monitor commodity price risk and take action to mitigate that risk if it is considered necessary in light of the group's overall product sales mix and forecast cash flows.

Under a Gas Sale & Prepayment Agreement entered into in 2016, the customer may elect for a financial settlement in lieu of taking physical delivery of gas. The delivery period commences one year after commissioning of the Northern Gas Pipeline. The financial settlement amount is either a base price per the agreement, or the weighted average price of gas delivered under any new Gas Sales Agreements ("GSA") entered into by the Consolidated Entity and supplied from the Production area, or a combination of both. The first new GSA commenced June 2017.

Volume Sensitivity

The financial liability is valued based on achieving take or pay volumes under new GSA's in existence. A sensitivity of 10% has been selected on the deliverable volumes under the new GSA's to show the impact on the carrying value:

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2018				
Other financial liabilities	—	1,040,756	—	—
2017				
Other financial liabilities	(1,730,218)	952,587	—	—

These movements would not have any impact on equity other than retained earnings.

Price Sensitivity

A sensitivity of 1% of the weighted average gas price under new GSA's has been to show the impact on the carrying value of the financial liability:

	PROFIT OR LOSS		EQUITY	
	1% Increase	1% Decrease	1% Increase	1% Decrease
2018				
Other financial liabilities	(152,789)	152,789	—	—
2017				
Other financial liabilities	(549,107)	106,703	—	—

These movements would not have any impact on equity other than retained earnings.

(e) Financing Facilities

The Group has a loan facility agreement ("Facility") with Macquarie Bank Limited ("Macquarie").

Interest costs are based on fixed spreads over the periodic Bank Bill Swap ("BBSW") average bid rate. The Facility is structured as a five year partially amortising term loan and has a maturity date of 30 September 2020. Repayments commenced December 2015 and comprise fixed quarterly principal repayments of $1 million along with accrued interest. The Group does not have any interest rate hedging arrangements in place. Central Petroleum Limited can repay the Facility in part or in whole at any time without a pre-payment penalty.

In April 2018 Macquarie agreed to an increase in the Facility D Commitment by $5,000,000 ("Second Facility D Loan"). As at 30 June 2018 the Group has not drawn on this facility. Should the Group draw down on the Second Facility D Loan, it will be repayable in quarterly instalments over calendar year 2019.

In September 2018 Macquarie agreed to increase the facility by a further $7.5 million (refer Note 34 for further details).

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(e) Financing Facilities (continued)

Under the terms of the Facility, the Group is required to comply with the following two key financial covenants:

1. The Group Current Ratio is at least 1:1, excluding amounts payable under the Macquarie debt facility
2. The Net Present Value with a 10% discount rate ("NPV10") of forecasted net cash flow from the Palm Valley, Dingo and Mereenie gas fields limited by the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount must be greater than 1.3:1.

The Group remains compliant with these and all other financial covenants under the Facility.

(f) Currency Risk

The Consolidated Entity's exposure to currency risk is limited due to its ongoing operations being in Australia and all associated contracts completed in Australian dollars. A foreign exchange risk arises from liabilities denominated in a currency other than Australian dollars. The Group generally does not undertake any hedging or forward contract transactions as the exposure is considered immaterial, however, individual transactions are reviewed for any potential currency risk exposure.

At reporting date the Group had the following exposure to foreign currency risk for balances denominated in US dollars from its continuing operations, which are disclosed in Australian dollars:

	2018 **$**	2017 $
Trade and other receivables	2,129,035	1,492,790

The following table details the Group's sensitivity to a 10% increase or decrease in the Australian dollar against the US dollar, with all other variables held constant. The sensitivity analysis is based on the foreign currency risk exposure at the reporting date.

	2018 **$**	2017 $
Australian dollar/ US dollar + 10%	(193,549)	(135,708)
Australian dollar/ US dollar -10%	212,904	149,279

These movements would not have any impact on equity other than retained earnings.

(g) Fair Values

The carrying amounts of cash, cash equivalents, financial assets and financial liabilities, approximate their fair values.

33. INTEREST IN JOINT ARRANGEMENTS

Details of joint arrangements in which the Consolidated Entity has an interest are as follows:

	PRINCIPAL ACTIVITIES	**2018** %	2017 %
OL4, OL5 and PL2 (Mereenie) (Macquarie[1])	Oil & gas exploration	50.00	50.00
EP 82 (Santos)	Oil & gas exploration	60.00	60.00
EP 105 (Santos)	Oil & gas exploration	60.00	60.00
EP 106 (Santos)	Oil & gas exploration	60.00	60.00
EP 112 (Santos)	Oil & gas exploration	60.00	60.00
EP 125 (Santos)	Oil & gas exploration	30.00	30.00
EP 115 North Mereenie Block (Santos[2])	Oil & gas exploration	60.00	60.00
EPA 111 (Santos[2])	Oil & gas exploration – application	50.00	50.00
EPA 124 (Santos[2])	Oil & gas exploration – application	50.00	50.00

[1] Macquarie Mereenie acquired 50% interest form Santos effective 1 January 2017
[3] Santos = Santos Group companies

33. INTEREST IN JOINT ARRANGEMENTS (CONTINUED)

The Joint Arrangements are accounted for based on contributions made to the Joint Operated Arrangements on an accruals basis. The principal place of business is Australia.

Santos' right to earn and retain participating interests in each permit is subject to satisfying various obligations in their respective farmout agreement. The participating interests as stated assume such obligations have been met, otherwise may be subject to change or negotiation.

ATP 2031 (under application)

In June 2018 an agreement was reached with Incitec Pivot Limited ("IPL") to form a 50:50 Joint Venture in respect of ATP 2031 effective on and from the Grant Date. Central has been announced as the preferred bidder but as at 30 June 2018 the Permit had not been formally granted. Under the agreement IPL will fund $10 million of the Group's joint venture obligations ($20 million in total) for appraisal drilling costs during the initial exploration period.

In August 2018, the Queensland government formally awarded the permit to Central.

The share in the assets and liabilities of the joint arrangements where less than 100% interest is held by the Company are included in the Consolidated Entity's statement of financial position in accordance with the accounting policy described in Note 1(b) under the following classifications:

	2018 $	2017 $
Current assets		
Cash and cash equivalents	516,573	396,972
Trade and other receivables	3,546,014	3,139,181
Inventory	1,522,351	1,357,192
Other financial assets	416,667	—
Total current assets	6,001,605	4,893,345
Non-current assets		
Property, plant and equipment	50,050,670	52,143,932
Other financial assets	393,360	175,000
Total non-current assets	50,444,030	52,318,932
Current liabilities		
Trade and other payables	1,083,012	605,789
Accruals	3,273,550	381,094
Deferred revenue	730,878	730,878
Total current liabilities	5,087,440	1,717,761
Non-current liabilities		
Deferred revenue	439,497	439,497
Provision for production over-lift	3,541,059	1,712,422
Restoration provision	12,352,212	11,658,569
Total non-current liabilities	16,332,768	13,810,488
Net assets / (liabilities)	35,025,427	**41,684,028**
Joint arrangement contribution to loss before tax		
Revenue	25,680,706	15,263,637
Other income	29,662	2,017,203
Expenses	(21,646,937)	(18,678,419)
Profit / (Loss) before income tax	4,063,431	**(1,397,579)**

34. EVENTS OCCURRING AFTER THE REPORTING PERIOD

In July 2018, it was announced that Mr Richard Cottee will cease employment on 31 January 2019. Mr Leon Devaney is acting CEO in the interim period.

In July 2018, the Consolidated Entity submitted objections in respect of its income tax assessments for the income years ended 30 June 2013 to 30 June 2016 inclusive. The objections relate to Research & Development Tax offsets and the treatment of Farmout Arrangements in respect of those years of income. As at 30 June 2018 the Consolidated Entity has not recognised any potential tax benefits from the objections lodged.

In August 2018, Central was formally awarded ATP 2031 by the Queensland government.

GRR's appeal opposing jurisdiction in the Supreme Court of Queensland was dismissed in the Company's favour on 14 September 2018 (refer to Note 29 (a) (iii) for further details).

On 26 September 2018 the Consolidated Entity's debt facility with Macquarie Bank was extended by a further $7.5 million. Drawdowns under this extension are at Central's election and will be repayable in equal instalments from April to December 2019. As part of the arrangement the Company will grant Macquarie Bank up to 22.5 million options with an exercise price of 14 cents and expiring December 2019. Options will be granted in four equal tranches, the first on completion of the agreement and the remaining tranches as funds drawn down under the facility reach certain thresholds.

On 27 September 2018 Central Petroleum Limited secured a $10,000,000 facility with Hong Kong based investment company Long State Investment Limited ("LSI"). Under the terms of the facility, Central Petroleum Limited may, at its discretion, issue shares to LSI at any time over the next 24 months, up to a total of $10,000,000. Central Petroleum Limited may draw down up to $250,000 in any period of 5 trading days.

Shares issued to LSI will be priced at the lowest daily volume weighted average price ("VWAP") of Central Petroleum Limited shares traded on each of the 5 trading days which follow an advance notice by Central Petroleum Limited. A commission of 5% will be payable by Central Petroleum Limited at the time of issue.

LSI may receive up to 5 million unlisted options through four separate tranches that are subject to ELOC utilisation. An initial tranche of 1.25 million options with an exercise price of 35 cents will be granted on activation of the ELOC. Further tranches of 1.25 million options, with an exercise price of 200% of the 20-day VWAP immediately preceding the date on which Central is required to grant the options, will be granted when the aggregate advances first exceeds $2.5 million, $5.0 million, and $7.5 million. The options have an exercise period of five years from the date of issue. To date, Central has not utilised the ELOC and no options have been granted.

No other matter or circumstance has arisen that will affect the Group's operations, results or state of affairs, or may do so in future years.

DIRECTORS' DECLARATION

In the Directors' opinion:

a) the financial statements and notes set out on pages 36 to 83 of the Consolidated Entity are in accordance with the *Corporations Act 2001* (Cth), including:

   (i) complying with Accounting Standards, the *Corporations Regulations 2001* (Cth) and other mandatory professional reporting requirements, and

   (ii) giving a true and fair view of the Consolidated Entity's financial position as at 30 June 2018 and of its performance for the financial year ended on that date;

b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable; and

c) the financial statements comply with the International Financial Reporting Standards as issued by the International Accounting Standards Board as disclosed in Note 1(a).

This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the *Corporations Act 2001* (Cth) for the financial year ended 30 June 2018.

This declaration is made in accordance with a resolution of the Directors of Central Petroleum Limited:

Martin Kriewaldt
Director
Brisbane

28 September 2018

Independent auditor's report

To the members of Central Petroleum Limited

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Central Petroleum Limited (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 30 June 2018 and of its financial performance for the year then ended

(b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

What we have audited

The Group financial report comprises:

- the consolidated statement of financial position as at 30 June 2018
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- the consolidated statement of profit or loss and other comprehensive income for the year then ended
- the notes to the consolidated financial statements, which include a summary of significant accounting policies
- the directors' declaration.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

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

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.

Materiality

- For the purpose of our audit we used overall Group materiality of $1.6 million, which represents approximately 1% of the Group's total assets.
- We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole.
- We chose the Group's total assets because it is a generally accepted benchmark in the oil and gas industry for entities of a similar size and stage of development.
- We selected 1% based on our professional judgement noting that it is within the range of commonly acceptable thresholds in the industry.

Audit scope

- Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events.
- The accounting processes are structured around the Group finance function located in Brisbane. Our audit procedures were mostly performed at the head office.

Key audit matters

- Amongst other relevant topics, we communicated the following key audit matters to the Audit and Risk Committee:
  - Basis of preparation of the financial report
  - Accounting for a gas forward sale agreement with a financial settlement clause
- These are further described in the *Key audit matters* section of our report.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context.

Key audit matter	***How our audit addressed the key audit matter***
Basis of preparation of the financial report *Refer to note 1(a)(i) of the financial report* In preparing the annual report, the Group has adopted the going concern basis of preparation. We considered the going concern assessment to be a key audit matter due to its importance to the financial report and given that the Group is growing, with competing demands for the available cash resources. This is typical of a company in the oil and gas industry at the Group's stage of development which requires capital to develop its resources and build infrastructure to be able to produce oil and gas.	The Group have prepared a going concern position paper and cash flow forecast model (the model) which concludes that the Group is a going concern for a period of at least 12 months from the date of signing the financial report. We considered this paper and model, focussing specifically on; • developing an understanding of the key cash flow items in the model, agreeing to supporting documentation where available; • consideration of the source and availability of funds; and • holding discussions with directors and management to understand any other potential cash flows that are not factored into the model. In relation to the financial statement disclosures, we considered the going concern basis of preparation disclosures in note 1 (a) (i) and their consistency with the Group's going concern position paper and model.
Accounting for a gas forward sale agreement with a financial settlement clause *(balance of $15.2m)* *Refer to notes 3(a) and 18 of the financial report* During the period to 30 June 2016, the Group signed a forward gas supply agreement with a counterparty under which the Group received funding which would be repaid in the future by way of gas supplies. The agreement provides the counterparty with an option to elect financial settlement rather than the receipt of gas. As such this arrangement was considered to be a financing arrangement and a financial liability was recognised, measured at amortised cost, at 30 June 2016, 30 June 2017, and 30 June 2018. The amount of any financial settlement, and hence the financial liability balance, is impacted by gas selling prices and volumes expected to be realised in the future from new gas supply agreements the Group enters into.	We performed the following procedures, amongst others: • held discussions with management and assessed contractual agreements to understand the nature of the gas forward sale agreement, and the calculation methodology of the financial liability; • held discussions with management and reviewed contractual agreements to ascertain the existence and nature of new gas supply agreements entered into during the period, and checking that the financial liability had been re-measured accordingly; • assessed the financial liability calculations for mathematical accuracy, and agreed key input assumptions into contractual agreements; • tested that the re-measurement of the liability had been appropriately classified in the statement of profit or loss and statement of financial position; and

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Key audit matter	*How our audit addressed the key audit matter*
During the period 30 June 2018, the Group signed a deed of novation agreement with the counterparty for the First Contract Year for the physical delivery of gas. The remaining year 2 and year 3 of the gas sales agreement retained the option to elect financial settlement rather than the receipt of gas. We considered this a key audit matter based on the materiality of the financial liability, and the judgement involved in re-measuring the financial liability based on the future expected sales volumes and prices.	• assessed the accounting impact of the novation of part of gas sales agreement to a third party, and the appropriateness of the reclassification of an amount of the financial liability to deferred revenue, and the measurement of that deferred revenue balance; • Evaluated the adequacy of the disclosures made in notes 3(a), 15, 18 and 32 in light of the requirements of Australian Accounting Standards.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2018, including the Chairman's Letter, Chief Executive Officer's Letter, Directors' Report, Corporate Directory, Corporate Governance Statement, ASX Additional Information, and Interests in Petroleum Permits and Pipeline Licences but does not include the financial report and our auditor's report thereon.

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

In connection with our audit of the financial report, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

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

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 23 to 32 of the directors' report for the year ended 30 June 2018.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2018 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Michael Shewan
Partner

Brisbane
28 September 2018

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 30 AUGUST 2018

Top holders

The 20 largest registered holders of the quoted securities as at 30 August 2018 were:

	NAME	NO. OF SHARES	%
1.	UBS Nominees Pty Ltd	32,632328	4.61
2.	Mr. Christopher Ian Wallin + Ms Fiona Kay McLoughlin + Mrs Sylvia Fay Bhatia <Chris Wallin Super Fund A/C>	17,571,648	2.48
3.	HSBC Custody Nominees (Australia) Limited – A/C 2	16,602,906	2.35
4.	Rocket Science Pty Ltd <The Trojan Capital Fund A/C>	15,800,000	2.23
5.	National Nominees Limited <DB A/C>	14,877,697	2.10
6.	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	2.00
7.	Citicorp Nominees Limited	13,994,187	1.98
8.	Fanchel Pty Ltd	12,716,667	1.80
9.	Telunapa Pty Ltd. <Telunapa Capital A/C>	10,541,667	1.49
10.	Kensington Capital Partners Pty Ltd	8,345,173	1.18
11.	National Nominees Limited	7,485,949	1.06
12.	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	7,400,000	1.05
13.	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	6,700,000	0.95
14.	Safari Capital Pty Ltd	5,484,967	0.78
15.	Chembank Pty Limited <R T Unit A/C>	5,000,000	0.71
16.	Mr. Jamie Pherous <Black Duck Holdings A/C>	5,000,000	0.71
17.	J P Morgan Nominees Australia Limited	4,947,391	0.70
18.	Bond Street Custodians Ltd <Macquarie Smaller Co's A/C>	4,767,155	0.67
19.	Edwin Holdings Pty Ltd	4,604,167	0.65
20.	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	4,500,000	0.64
		213,138,569	30.14

DISTRIBUTION SCHEDULE

The distribution schedule of the ordinary fully paid shares as at 30 August 2018 was:

RANGE	HOLDERS	UNITS	%
1 - 1,000	802	369,324	0.05
1,001 -5,000	2,141	5,889,802	0.83
5,001 - 10,000	1,150	9,000,559	1.27
10,001 - 100,000	2,969	114,367,251	16.18
100,001 - Over	989	577,488,857	81.67
Total	8,051	707,115,793	100.00

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 30 August 2018 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

HOLDER	UNITS
Troy Harry	38,245,173

ASX ADDITIONAL INFORMATION

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 5,000 shares as at 30 August 2018):

HOLDERS	UNITS
2,411	3,889,395

VOTING RIGHTS

Subject to any rights or restrictions for the time being attached to any class or classes of shares, at meetings of shareholders or classes of shareholders:

- each shareholder entitled to vote may vote in person or by proxy, attorney or representative of a shareholder;
- on a show of hands, every person present who is a shareholder or a proxy, attorney or representative of a shareholder has one vote; and
- on a poll, every person present who is a shareholder shall, in respect of each fully paid share held by him, or in respect of which he is appointed a proxy, attorney or representative, have one vote for their share, but in respect of partly paid shares, shall have such number of votes being equivalent to the proportion which the amount paid (not credited) is of the total amounts paid and payable in respect of those shares (excluding amounts credited).

ON-MARKET BUY BACK

There is no current on-market buy-back.

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES AT THE DATE OF THIS REPORT

PERMITS AND LICENCES GRANTED

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks) [1]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 93 [4]	Pedirka Basin NT	Central	100	0		
EP 97 [4]	Pedirka Basin NT	Central	100	0		
EP 105 [1]	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106 [3]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 107 [4]	Amadeus/Pedirka Basin NT	Central	100	0		
EP 112 [1]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 115 (excl. EP 115NMB)	Amadeus Basin NT	Central	100	100		
EP 115NMB (North Mereenie Block)	Amadeus Basin NT	Santos	60	60	Santos	40
EP 125	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	100	100		
OL 4 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
OL 5 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	100	100		
RL 3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna)	Amadeus Basin NT	Central	100	100		
ATP 909	Georgina Basin QLD	Central	100	100		
ATP 911	Georgina Basin QLD	Central	100	100		
ATP 912	Georgina Basin QLD	Central	100	100		
ATP 2031 [6]	Walloon Fairway QLD	Central	100	50	Incitec Pivot	50

PERMITS AND LICENCES UNDER APPLICATION

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111 [2]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124 [2 & 5]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 129	Wiso Basin NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 131 [4]	Pedirka Basin NT	Central	100	100		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133	Amadeus Basin NT	Central	100	100		
EPA 137	Amadeus Basin NT	Central	100	100		
EPA 147	Amadeus Basin NT	Central	100	100		
EPA 149	Amadeus Basin NT	Central	100	100		
EPA 152	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		
EPA 296	Wiso Basin NT	Central	100	100		

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES AT THE DATE OF THIS REPORT

PIPELINE LICENCES

PIPELINE LICENCE	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	50	50	Macquarie	50
PL 30	Amadeus Basin NT	Central	100	100		

1 *Santos' right to earn and retain participating interests in the permit is subject to satisfying various obligations in their farmout agreement with Central. The participating interests as stated assume such obligations have been met, otherwise may be subject to change.*

2 *Effective 1 May 2017, Santos exercised its option to acquire a 50% participating interest in and be appointed operator of EPA 111 and EPA 124, which was granted as part of Central's acquisition of a 50% interest in the Mereenie oil & gas field.*

3 *Santos (as Operator) has continued the process of an application with the NT Department of Primary Industry and Resources for consent to surrender Exploration Permit 106.*

4 *These exploration permits and exploration permit applications and have been disposed subject to approval from the NT government and Department of Primary Industry and Resources.*

5 *On 22 March 2018 (in respect EPA 124) and on 23 March 2018 (in respect of EPA 152) Central received notice from the NT Department of Primary Industry and Resources that EPA 124 and EPA 152, as applicable, had been placed in moratorium for a period of 5 years from 6 December 2017 until 6 December 2022.*

6. *ATP 2031 was granted in August 2018.*