Central Petroleum

Annual Report 2017

Cracking the code

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CORPORATE DIRECTORY

DIRECTORS

Robert Hubbard FCA, Non-executive Chairman
Richard I Cottee BA, LLB (Hons), Managing Director and Chief Executive Officer
Wrixon F Gasteen BE (Hons), MBA (Dist), Non-executive Director
Peter S Moore BSc (Hons1), MBA, PhD, Non-executive Director

GROUP GENERAL COUNSEL AND JOINT COMPANY SECRETARY

Daniel C M White LLB, BCom, LLM

JOINT COMPANY SECRETARY

Joseph P Morfea FAIM, GAICD

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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 ROBERT HUBBARD

Dear Fellow Shareholders

I appreciate that it is customary for annual reports to provide a scorecard for the year that has passed and a commentary on the key events and I will of course do this. However, the year's events were cloaked in the corporate activity as a consequence of the unsolicited takeover offer from Macquarie Bank. This is now behind us and I believe any further focus on these events would neither be in the best interests of Central, its shareholders nor our many other stakeholders.

We are now singularly focused on taking advantage of the tightening east coast gas market and creating further economic development in the Northern Territory. In June 2017 we set ourselves 4 goals and we have made significant progress on each one in the brief time since that date. These goals were:

- Raising sufficient equity capital to fund our reserve growth strategy. We were keen to do this, at least in part, through a rights issue which was completed in September.
- Maintaining the focus on pipeline tariff reform and we remain encouraged by the positive announcements since the disappointing interim findings of the Gas Market Reform Group released in early June.
- Developing a go to market strategy with our Mereenie joint venture partner that will maximise market opportunities by acting in a collaborative manner, a key tenet of which was announced on 25 September 2017 and remains subject to ACCC approval.
- Initiating board succession planning aimed at further growing the depth and capability of the board. We remain on track to update shareholders by the time of the AGM.

Central has had another year of significant progress operationally and financially with growth in oil and gas production and revenues, continued focus on costs and the securing of the EDL gas contract for supply which commenced in June 2017. The financial performance for the year was marred by the mark to market loss on the Macquarie gas prepayment contract, where repayment will commence either financially or through the supply of gas. However, operational financial performance should continue to improve in 2017/18 with Central essentially self-funding ensuring all funds from the capital raising will be devoted to the drilling programme.

Central has and will continue to take an active part in debating the issues key to the Northern Territory. The social and economic consequences of a fly in fly out workforce remains a hot topic. Our local employment and sourcing policies sets Central apart from this debate. Importantly, our pursuit of these policies was not a tactic by Central but reflects our values and our vision for the Company we strive to be. We appreciate the right of our communities to demand the highest levels of environmental management and for our employees to have a safe workplace. Our performance in both these areas has again been noteworthy while growing the Company from a junior explorer to a mid-tier production company without either a Lost Time Incident or Reportable Environmental Incident. Further, the Company looks to continuously improve our performance in these and all other aspects of our operations.

The upcoming year has the potential to be the most significant since Central made its pivot to gas with the acquisition of the Magellan assets and Mereenie joint venture interest. The planned drilling programme, construction of the NGP and the emerging market opportunities should all be viewed with great excitement.

Central's achievements are a team effort and I would like to thank my colleagues on the Board, all of whom have made significant contributions this year. An unusually large number of board meetings and much time spent out of the boardroom has never been questioned. Richard Cottee and his accomplished team led by Mike Herrington, operationally and Leon Devaney, commercially have again ensured Central punches above its weight.

In closing I would like to thank all our shareholders, the tenacity of those who have been on the journey with Central for many years and those that have recently joined the Central register for your collective confidence in our strategy.

Best wishes

Robert Hubbard
Chairman
Brisbane

25 September 2017

MANAGING DIRECTOR'S LETTER

Dear fellow Shareholders

The past financial year has been transformatory for Central as the company pushed ahead despite massive headwind from low prices, an investment drought, political interventions, regulatory disruption and opportunistic takeover proposals. Each threat was addressed or turned to Company and shareholder advantage.

The Gas Acceleration Program ("GAP") upon which the company embarked require the company to achieve certain milestones such as access to market (the "Northern Gas Pipeline") at a competitive price ("pipeline tariff reform") access to capital to enable to increase reserves. We have now got all those ducks in a row. We emerge from FY2017 with free cash flow for the first time, strong prospects from secure tenements, a funded drilling programme and a real market opportunity to supply into the East Coast gas shortage.

The unsolicited offer by the Macquarie Group masked the real and substantial progress the company was making. After rejecting an initial proposal the Board negotiated a superior proposal by way of a Scheme of Arrangement (SoA) which was accepted by 68% of the shareholders voting. As the required threshold was 75% in favour, the SoA was defeated.

Notwithstanding, the SoA had a threefold enduring benefits for the company namely:

1) It publicised the Company's pre-eminent positive opportunity in the East Coast Gas Market and the Gas Acceleration Program itself;

2) It provided strong credible "independent" validation that the stock market was materially undervaluing the Company; and

3) It lay the foundations, by its enhanced disclosure in the "Scheme Booklet", for the company to subsequently raise the necessary drilling funds and pursue reserves growth in time for the Northern Gas Pipeline ("NGP") commissioning.

The Macquarie proposal did not distract the Company from its operational and strategic goals. During the year the Company was able to achieve significant milestones and navigate successfully a number of major new barriers placed in its way. This was a real testimony to management's and staff's dedication to enhancing shareholder value. The following are some of the achievements during the year.

1) Local and Indigenous Employment Strategy

By implementing our employment philosophy, first established in March 2015, the Company has been able to reach a good balance of local and Fly in Fly out ("FIFO") workers whilst continuing to improve its safety and environmental performance. Our employment mix is now 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.

2) Fraccing Moratorium

In August 2016, the new NT Government announced a Fraccing Moratorium which did not impact Central's conventional gas operations. More recently the NT Government announced a commitment to local employment as part of its mining approvals process, an issue on which the Company already complies.

3) Pipeline Reforms

In 2016 the ACCC Inquiry into East Coast Gas Market highlighted monopoly pricing in the pipeline sector which has been a significant barrier to new investment in the sector with a limiting impact on the Company's ability to be a new supply source and supplier to the East Coast Gas Market. In August 2016 the Council of Australian Governments (COAG) commissioned Dr Michael Vertigan to review the ACCC's proposed reforms and make recommendations aimed at putting "downward pressure" on transportation costs. Both of these inquiries were actively promoted and supported by Central through many stages leading to the Gas Market Reform Group and Energy Ministers adopting a new pipeline valuation methodology which can be expected to produce a positive impact on the Company's transportation costs to market.

The Company continues to invest heavily in the Gas Market Reform process with the AEMC now conducting an equivalent review of "covered" pipelines. This commitment is highlighted by our CFO (Leon Devaney) being appointed as a GMRG Project Team Member.

4) New Gas Supply Agreement

The Company entered into a new GSA with EDL in April 2017. The first gas under this contract was sold in June 2017 with revenues commencing this financial year. The result is that this year will be the first year in which the company is able to forecast positive cash flows.

5) Drilling Prospects

During the year, the Company targeted the gas bearing Stairway formation which overlays the present oil and gas producing zones in Mereenie. Substantial effort was put into modelling the natural fractures in that formation. Independent Experts RISC reported in the Scheme Booklet on page 222 stated:

"RISC has reviewed Central's simulation model, analytical models and supporting documentation. In their simulation work, Central focused on history matching the gas phase as this was the focus of future development. RISC considers the cumulative production and rate history matching at the field level and well pressure matches in the gas phase to be robust"

This endorsement led the Company to commence the same process at Palm Valley and RISC, after having performed an independent peer review of the work performed by Central, has stated in a subsequent letter that Central's work is "credible". By end of July 2017, the Company was ready and confident that it had a promising and credible four well Appraisal Drilling programme requiring approximately $25 million in equity capital to be raised. This was the culmination of two years of dedicated effort.

6) Funding

Armed with its endorsed Drilling Programme and taking advantage of the large amount of disclosure occasioned by the SoA, the company successfully undertook a fully underwritten $27 million funds raising which, after costs, netted over $25 million.

The company has achieved a high degree of publicity, endorsement of its value proposition by a credible and independent 3rd party, an increasingly economic pathway to a robust domestic gas market and is finally adequately capitalized to take advantage of that market.

Let the Rocks speak.

Yours faithfully

Richard Cottee
Managing Director
Brisbane

25 September 2017

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2017

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 2017.

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
Richard I Cottee
Wrixon F Gasteen
Peter S Moore
J Thomas Wilson (resigned 15 July 2016)

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 (2016: $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:

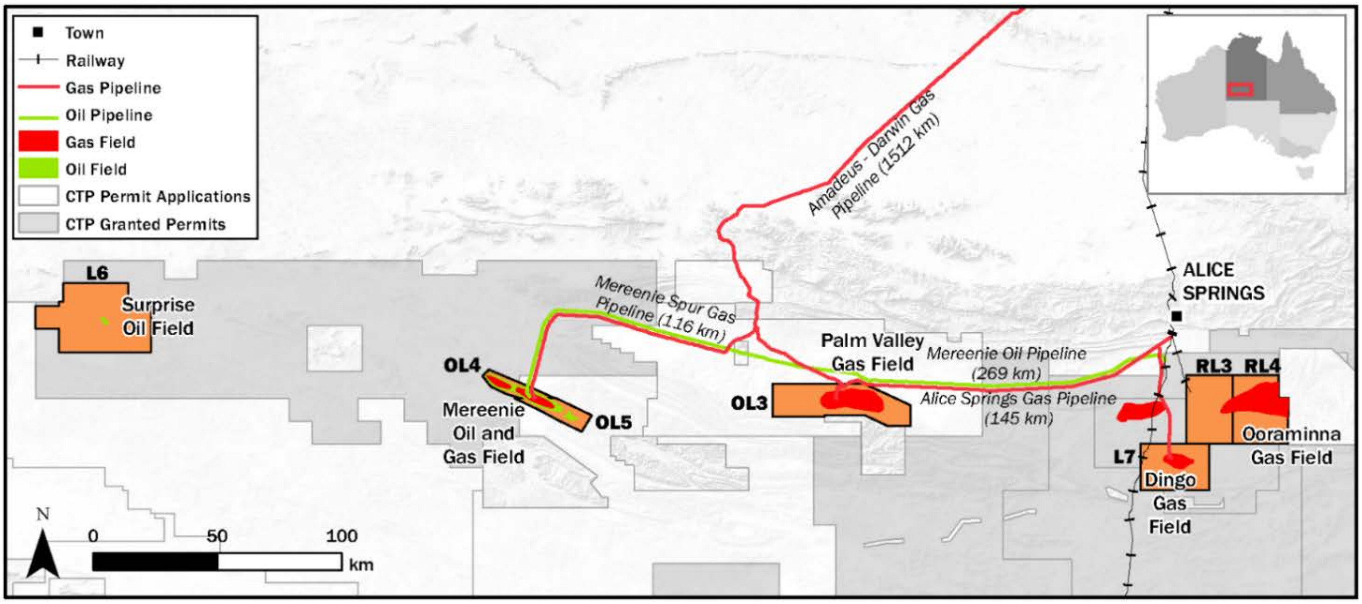
- The Company's safety and environmental performance has again been noteworthy without incurring either a Lost Time Incident or Reportable Environmental Incident while growing the Company from a junior explorer to a mid-tier production company.
- A new Gas Supply Agreement was entered into with EDL NGD (NT) Pty Ltd ("EDL") to supply 9.85PJ of gas over five years to the Northern Territory Pine Creek Power Station. Deliveries commenced 1 June 2017.
- Testing of the Stairway Sandstone at Mereenie from the previously drilled West Mereenie-15 continues free flowing gas at an average 1.1 million cubic feet per day (approximately 1.1 TJs/day) with a low nitrogen content of 2.6%. Additional recompletion opportunities have been identified.
- Dingo TEG unit being ordered as part of the Dingo upgrade for the Owen Springs Power Station upgrade.
- Palm Valley fracture modelling commenced to ascertain development well infill drilling opportunities.
- Mereenie natural fracture modelling was completed and two drilling locations selected (potential gross 2P target of 95-160BCF (110-185PJ).
- The Vertigan Report was adopted by the Council of Australian Government's Energy Ministers on 14 December 2016 foreshadowing a basic structural reform of pipeline tariffs and services. Central made a submission to the Gas Market Reform Group ("GMRG") Options Paper in April 2017 addressing concerns over backhaul tariffs that would be incurred to access East Coast markets.
- Amendments to the National Gas Rules with respect to non-scheme ("unregulated") pipelines has now passed through the legislative process and Central welcomes those amendments dealing with asset valuation techniques aligned to a cost recovery basis rather than accounting depreciation. Central is hopeful that this outcome will lead to a similar outcome for regulated pipelines which would in turn lead to lower transportation costs for Central's gas to the City gate in Sydney.
- Central made a submission to the NT's Scientific Inquiry into Hydraulic Fracturing of unconventional shale gas.
- Total elected not to proceed with Stage 2 of the SGJV farmin meaning the acreage reverts 100% to Central. Central was relieved of a contractual $2 million due to be spent.
- Macquarie Mereenie Pty Ltd, a subsidiary of Macquarie Bank Limited, acquired 50% of the Mereenie Oil & Gas field from Santos to become a joint venture partner with Central remaining as operator.

- Santos has acquired 932km of seismic data aimed at delineating the Dukas prospect of which Central holds 30% (which according to Santos is a multi TCF gas and helium target). There are good indications of improved seismic imaging with improved definition of the Dukas Lead and the additional potential for a super-salt lead. A five month extension to both phase 2 and phase 3 of the Farm-In have been agreed.
- Production workforce in the Northern Territory on an FTE basis transformed to:
  - One-third local indigenous
  - One-third local non-indigenous
  - One-third FIFO
- Restructuring initiatives during the first half of the financial year expected to reap ongoing benefits of $700,000 annually.
- Free carry obligations under the Mereenie Acquisition were settled with a $3.3 million payment to Santos.

Operating Result

The Consolidated Entity had an operating loss after income tax for the year ended 30 June 2017 of $24.73 million (2016: loss of $21.04 million). On an underlying EBITDA[1] basis, the Consolidated Entity achieved a full year net income of $0.32 million (2016: loss of $1.17 million). In addition, non-cash share based payment expense included in the above results amounted to $2.25 million (2016: $2.24 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 111,380 barrels of crude oil (2016: 98,635 barrels) and 3,322 TJ of gas (2016: 3,230 TJ). The increase reflects a full year contribution from the Mereenie oil and gas (10 months prior year).
- **Sales Revenue** of $24.79 million, up 9% on the previous financial year, reflecting increased production as a result of the full year contribution of the Mereenie asset and Dingo gas field. An average oil price of A$66 was realised during the year, up from A$58 in the prior corresponding period.
- **Underlying loss**[1] of $15.27 million, down from an underlying loss of $17.87 million in the prior year, a 15% improvement.
- **Exploration expenditure** decreased to $1.90 million in 2017 from $4.03 million in 2016
- **Net cash outflow from operations** of $0.2 million, an improvement from a net cash outflow in 2016 of $1.5 million. Cash flows for 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:

	2017 $ million	2016 $ million
Statutory loss after tax	(24.73)	(21.04)
Add/(less):		
One-off operating expenses (bonus restructuring)	—	1.73
R&D refunds	(0.63)	—
Restatement of financial liabilities[1]	9.49	—
Impairment of exploration assets	0.09	1.40
Impairment of oil producing properties	—	0.04
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	**(15.27)**	**(17.87)**

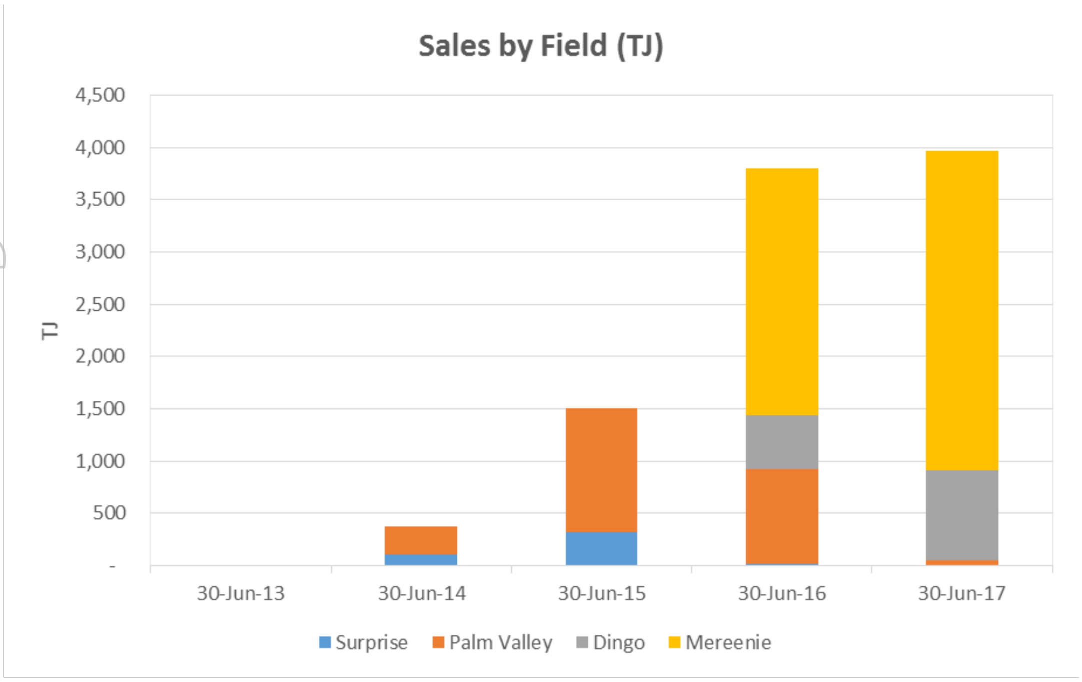
[1] Relates to a prepaid gas sales agreement containing a cash settlement option. If the cash settlement option is exercised, (instead of physical delivery of gas), payment will be satisfied out of future gas sales revenues from those gas sales agreements to which the cash settlement option is linked.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

Financial Review

The Company continued its transformation from an exploration company to an exploration and production company during the year ended 30 June 2017. Underlying loss improved by 15% on the previous financial year.

Key Metrics	**2017**	2016	**Percentage Change***
Net Sales Volumes			
Oil (barrels)	111,380	98,635	13%
Natural Gas (TJ)	3,322	3,230	3%
Average realised oil price (A$ per barrel)	66.42	58.15	14%
Sales revenue ($ million)	24.79	22.64	9%
Underlying EBITDA ($ million)	0.32	(1.17)	127%
Underlying Loss ($ million)	(15.27)	(17.87)	15%
Statutory loss (after tax)	(24.73)	(21.04)	(18)%
Cash ($ million)	5.48	15.11	(64)%

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



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

EBITDA

Underlying earnings before interest, tax, depreciation and amortisation (EBITDA) was $0.32 million, compared to a loss of 1.17 million in the prior year. The result reflects the full year contribution of the Mereenie assets.

A reconciliation of underlying EBITDA is shown below.

	2017 $ MILLION	2016 $ MILLION
Underlying loss after tax	(15.27)	(17.87)
Add/(less):		
Net interest	7.81	8.30
Income tax	—	—
Depreciation and amortisation	7.78	8.40
Underlying EBITDA[1]	**0.32**	**(1.17)**

[1] Underlying EBITDA includes non-cash share based payment expense of $2.25 million (2016:$2.24 million)

Gas sales from Dingo did not achieve full contracted volumes as the customer continues to take gas below the Annual Contract Quantity. Dingo Take-or-Pay revenue of $4.0 million that was generated for the contract year to 31 December 2016 was not recognised as revenue during the reporting period. This Take-or-Pay revenue was received in January 2017 and will be accounted for as revenue in future periods in accordance with the Group's revenue recognition policy (refer Note 1(e)(i)).

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

Sales Volumes

Sales volumes for both oil and gas increased from 2016, reflecting a full year contribution from the Mereenie asset which was acquired 1 September 2015.

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 PWC GSA, revenue associated with Take-or-Pay during the 2016 calendar year was received in January 2017 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

In line with the increase in world crude oil prices, and partly offset by a higher Australian dollar, the average realised price per barrel of oil increased 14% on the previous financial year. In financial terms, this represented an increase in revenue of approximately $0.9 million based on 2017 oil sales.

Gas prices generally reflect long-term fixed gas pricing structures with CPI related escalation, and are therefore not impacted by global energy markets.

Other Income

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. This resulted in the extinguishment of accrued liabilities amounting to $2.02 million recognised in other income during the 2017 financial year.

In fiscal year 2017, Research and Development refunds totaling $0.63 million were recognised as income, arising largely from exploration activities in the Southern Georgina and Southern Amadeus basins undertaken during the 2016 financial year. No Research and Development refunds are recognised in income in the Profit and Loss for the year ended 30 June 2016.

Restatement of financial liabilities

The statutory loss for the year ended 30 June 2017 includes a non-cash expense of $9.49 million relating to the restatement 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 increased from $0.51 million in fiscal year 2016 to $1.95 million in fiscal year 2017. The increase was largely a result of one off costs associated with the proposed Scheme of Arrangement along with higher legal costs in respect of the alleged litigation claim filed in Houston, Texas, partly offset by lower occupancy and other general and administrative expenses.

Employee Benefits and Associated Costs

Employee costs, net of recoveries to Operational and Exploration activities, increased to $5.66 million from $4.48 million in the previous financial year. Gross costs before recoveries increased 4.3% reflecting annual remuneration increase and some labour restructuring costs associated with localizing the NT workforce. Recoveries from operations were lower as a result of Total's withdrawal from the Southern Georgina Joint venture and reduced capital projects.

Cash

At 30 June 2017, consolidated cash and cash equivalents available totaled $5,478,140 (2016: $15,115,699), including $396,972 (30 June 2016: $676,283) held in joint venture bank accounts. Of this balance $1,421,848 relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2016: $4,981,343), 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 2017 was 0.60 (2016: 0.56). 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 $85.70 million at 30 June 2016 to $82.17 million at 30 June 2017 as the consolidated entity continues to make quarterly principal and interest repayments.

Capital Expenditure

Capital expenditure for fiscal year 2017 was $0.96 million, down from $2.86 million in 2016 (excluding the Mereenie asset acquisition).

Comparative Data

The following table and discussion is a one year (and five year) comparative analysis of the Consolidated Entities' 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.

	2017 $ MILLION	2016 $ MILLION	2015 $ MILLION	2014 $ MILLION	2013 $ MILLION
Financial Data					
Operating revenue	24.79	23.86	10.31	3.72	—
Exploration expenditure	1.90	4.03	7.66	4.66	6.98
Loss after income tax	24.73	21.04	27.73	10.86	9.28
Equity issued during year	—	11.52	5.56	24.97	7.56
Property, plant and equipment	106.82	113.78	58.58	46.27	1.28
Borrowings	(82.17)	(85.70)	(47.46)	(23.76)	—
Net Assets (Total Equity)	(5.96)	16.52	23.15	43.07	24.65
Net Working Capital	0.73	5.33	(4.41)	2.78	4.93
Operating Data					
Gas Sales (GJ)	3,321,731	3,230,473	1,194,153	267,328	—
Oil Sales (barrels)	111,380	98,635	53,925	17,489	—
No. of employees at 30 June	83	83	58	51	26

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.

By its nature, exploration is an extremely high risk business. Most exploration activity, in particular seismic and drilling, is conducted in joint venture, 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 environment. In addition, as with most businesses, there is also market risk, product pricing risks and foreign exchange risk. Exploration is typically funded with risk capital. Debt capital is normally only available for development activities such as facility and pipeline construction.

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.

Central's key operating risks include 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.

Central is continually seeking to access new and higher value markets like the east coast gas market via the Northern Gas Pipeline (NGP). The east coast gas market, however, is currently undergoing a substantive restructuring of supply and demand following commencement of 3 LNG projects in Queensland. This has placed significant upward pressure on delivered gas prices in 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 substantive regulatory review and reform by Federal Government agencies. The outcome of these reviews will be material to Central's ex-field gas pricing received from east coast customers.

Business Strategy

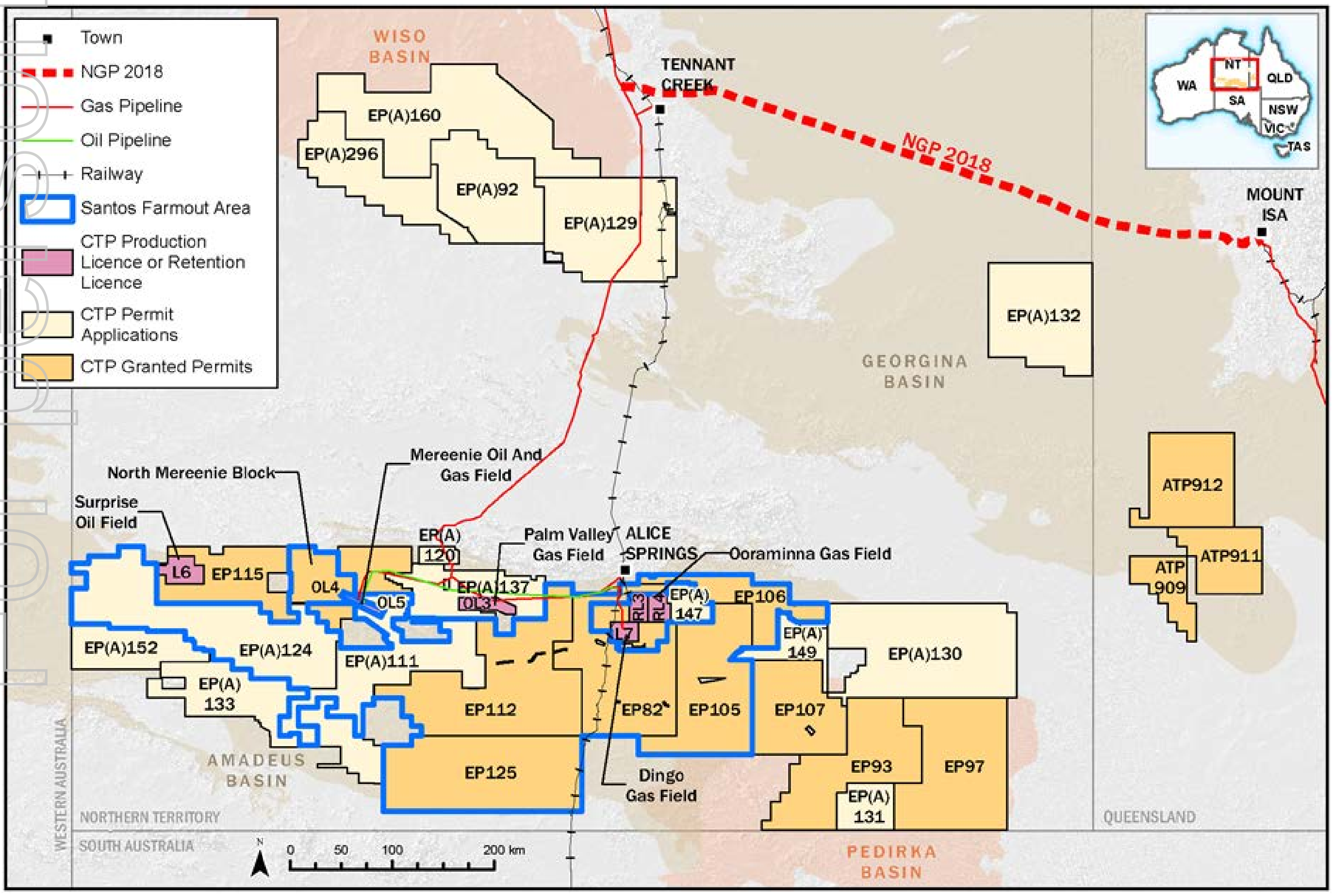
Over the past three years, Central has developed and successfully pursued a strategy to take advantage of a tightening domestic gas market to gain critical mass in conventional gas production and uncontracted gas reserves. This strategy first crystalised through the acquisition of the Palm Valley and 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 substantive onshore domestic gas producer, with approximately 11 TJ/d contracted sales equity accounted (4PJ p.a.) and growing uncontracted conventional gas reserves from proven fields. Central is currently undertaking a 4-well drilling program with a target of tripling our uncontracted 2P reserves to between 300 PJ and 400PJ (equity accounted). Whilst available for delivery in late 2018 for the domestic gas shortfall, which should begin to bite in that year, completion of certification of the reserves will take longer and occur over time .

With the Mereenie, Palm Valley and Dingo fields under our common operatorship, Central is now in a unique position to participate (and actively support) the Northern Gas Pipeline ("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 sound business strategy of acquiring gas assets and uncontracted reserves in advance of the NGP pipeline has positioned it to be a direct and substantive beneficiary.

Whilst the implementation of Central's Business Strategy has been relatively swift, the aggressive and sustained downturn in oil prices has served to justify our transition into gas starting three years ago. The acquisition of Palm Valley, Dingo, and Mereenie have all been acquired based on existing gas contracts which are structured as long-term fixed price, CPI escalated. This provides a solid revenue stream going forward to cover Central's operating activities and debt financing arrangements secured on long term gas contracts that are not affected by oil price or currency movements and, therefore, largely unaffected by turmoil in international oil or LNG markets. Any future reserve additions and gas sales agreements will result in substantive value accretion to those assets.

Accessing new and higher-value markets for our gas should materially re-rate our significant under-explored permits throughout the Amadeus, Southern Georgina, Pedirka and Wiso basins in Central Australia. Going forward, our operations now allow Central to be cash flow positive after debt service which means that the capital available through the recent equity raise can be fully dedicated to growing high value conventional gas reserves throughout our various exploration permits.



Granted Petroleum Permits, Licences and Application Interests

Operations and Activities

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2016/17	FY 2015/16
Gas	TJ	3,322	3,230
Crude and Condensate	bbls	111,380	98,635

Palm Valley Gas Field (OL3)

Northern Territory
(CTP — 100% Interest)

As a result of the acquisition of 50% of the Mereenie field, the Palm Valley gas field has been placed in standby to reduce operating costs while contracted gas is supplied by Mereenie.

The Palm Valley Shallow Prospect has been updated with additional data collected from surface mapping. The initial results are positive, and the Company intends to conduct additional natural fracture mapping to refine the prospect.

The main producing reservoirs at Palm Valley are the Lower Stairway and Pacoota formations. To date, ~160 Bcf of gas has been produced from the naturally fractured reservoir. OGIP estimates vary greatly over the field, but all are in excess of 1 Tcf. With the current wells, the EUR is predicted to be around ~200 Bcf, this is a very low recovery factor for a naturally fractured reservoir and implies a large quantity of gas still remaining in the ground. Production performance and interference testing have shown that the existing wells may not be connected to the total estimated gas in place volume, which implies that there are other compartments of the field that have not been drained and contain gas in possibly producible quantities. To determine the possible location and size of these areas that could be segregated from the producing wells, a natural fracture model is being created with data from seismic, outcrop, image logs, production and core data. Where the model predicts unconnected resources, infill drilling will follow to prove the hypothesis, potentially leading to an increase in 2P reserves.

- All repairs completed at the plant and the plant remains on standby ready for production.
- Instrumentation engineering study conducted to determine scope of work to remotely operate field.
- Compressors started periodically.

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

Northern Territory
(CTP — 100% Interest)

- Concept design complete and tenders let for Dingo 2 TEG Unit and water bath heater to control hydrate formation at the plant and well site, respectively.
- The field continued to supply Owen Springs Power Station.

Central conducted a review of geological and engineering data, leading to a belief in upside potential of the field. Internationally recognised petroleum consultants Netherland, Sewell & Associates, Inc. ("NSAI") estimated petroleum reserves and supported an increase in contingent resources as announced to the ASX on 21 July 2015.

Several structural leads were identified in the area immediately surrounding Dingo gas field, within 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.

Ooraminna Field

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 is currently being updated following recent reprocessing of the seismic data. This will be augmented by outcrop mapping to assist in structural definition between seismic lines. This updated mapping will be incorporated into a natural fracture model which will predict areas with the greatest fracture density.

The Ooraminna field has an inferred closure area of ~175 km2 and preliminary estimates of OGIP for the Pioneer formation range from ~125 Bcf to ~425 Bcf. Currently, there are no resources certified at Ooraminna, however, demonstrating increased productivity through horizontal drilling in areas of predicted increased natural fracture density, will lead to resource certification.

No significant developments occurred in Central's other exploration and application areas during the quarter. However, Central continues to work with stakeholders and progress discussions pertaining to the grant of application areas and rationalisation of non-core exploration areas.

Mereenie Oil and Gas Field (OL4 and OL5)

CTP-50% interest [Operator], Santos-50% interest purchased by Macquarie Bank effective January 1, 2017.

- On 26 April 2017, Central announced the signing of a Gas Supply Agreement with EDL NGD (NT) Pty Ltd ("EDL") to supply 9.85PJ of gas over five years to the Northern Territory Pine Creek Power Station operated by EDL.
- Delivery of gas from Mereenie to Pine Creek under the EDL GSA commenced on 1 June 2017.
- Annual pre-budget Technical Committee Meeting (TCM) and Operating Committee Meeting (OCM) with Macquarie was conducted on 4 May 2017. The Macquarie representative was briefed on all aspects of Operations, including; production, projects, safety and environment. Macquarie was also introduced to potential activities and projects for FY 17/18 and provided with a draft budget to meet a range of scenarios.
- An inspection and audit was carried out by Northern Territory (NT) Worksafe on 22-23 March, 2017 with no non-compliances noted.
- NT DPIR management visited BECGS and Mereenie on 30/31 March, 2017 with no non-compliances noted.
- Central continued to work on development planning for Mereenie to provide additional supply into the Northern Territory or the Northern Gas Pipeline (NGP) in late 2018. Including:

Stairway Sandstone at Mereenie

West Mereenie 15 is currently producing approximately 200mscf/d from the Upper Stairway formation. The well was shut-in recently to continue to gather pressure build-up data. Through decline curve and pressure transient analysis, it is confirmed that the well is producing from a dual porosity/permeability system, with natural fractures and matrix both contributing to production and the natural fractures enhancing the productivity and estimated ultimate recovery (EUR). Natural fractures have been identified in outcrop, core and wireline logs. Also, the Lower Stairway formation in the eastern part of the field produced ~2 Bcf from a vertical well. Natural fracture data gathering and modelling of the Upper and Lower Stairway formations was undertaken to predict areas with the greatest natural fracture density. Preliminary estimates of original gas in place (OGIP) for both the Upper and Lower Stairway range from ~240 Bcf to ~400 Bcf and the CTP reserve auditor (NSAI) has certified 120 PJ of 2C resources. By targeting areas of predicted increased natural fracture density with horizontal wells, productivity and EUR are predicted to convert resources to reserves. Existing wells will also be utilized where possible in order to significantly reduce capital expenditure associated with converting resources to reserves.

Figure 1: *Back of control room at Central Treatment Plant (CTP)*

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(Joint Venture between CTP - 100% interest [Operator] and Total – Withdrew)

Central met with the Department of Natural Resources and Mines (DNRM) regarding its application for Project Status over the three Queensland permits. Initial discussions have been positive and drafting of the application will follow.
Central is working through the DNRM process to transfer the previously Total held 10% back to Merlin Energy Pty Ltd.

Southern Amadeus Basin

Northern Territory
Various Exploration Permits (see table on page 86)

Santos Stage 2 Farm out – Southern Amadeus Basin, Northern

After the completion of detailed analysis of integrated seismic, gravity, historic well data and selection of line locations, the final Land Access and Compensation Agreement for the Amadeus 2D seismic survey was completed, Ministerial approval was obtained for seismic data acquisition which commenced in November 2016. At present a total of 932 km of seismic line data have been acquired – 72% of the total 1,300 line km 2D required to meet Phase 2 Farm-in requirement.
There are good indications of improved seismic imaging as a result of the new acquisition parameters with improved definition of the Dukas Lead and the additional potential for a supra-salt lead. A five month extension to both phase 2 and phase 3 have been agreed.

Southern Amadeus Area	Total Santos Participating Interest after completion of Stage 1	Total Santos Participating Interest after completion of Stage 2
EP82 (excluding EP82 Sub-Blocks)	25%	40% (i.e. additional 15% earned)
EP105	25%	40% (i.e. additional 15% earned)
EP106 *	25%	40% (i.e. additional 15% earned)
EP112	25%	40% (i.e. additional 15% earned)

* 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.

The survey comprises two rounds. The first round of 2D seismic is to mature the natural gas and helium prospective Dukas lead and to gather data for the Rossini lead has been completed. The second part of the seismic acquisition program will consist of additional 2D seismic lines over the Dukas Lead to bring the total program to 1,300 line km. Second round line locations are being confirmed for resumption of data acquisition in July. Adverse weather conditions in the area have caused the focus to be concentrated on the Dukas Lead.
Central is actively reviewing data in these permits, seeking to upgrade a variety of exploration play types and targets, which could be prospective for hydrocarbons and/or helium.

The joint venture's exploration endeavours on these four permits focus on maturing large sub-salt leads. The primary reservoir objective is the Heavitree Quartzite. Secondary reservoir objectives in the Neoproterozoic units include the Areyonga Fm and Pioneer Ss which are gas bearings in the Ooraminna field.

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.

Surprise Oil Field (L6)

Northern Territory
(CTP — 100% Interest)

- Surprise West remained shut-in since July of 2015. The well has been temporarily shut-in to gather pressure data to assess the re-charge potential of the field. Should oil prices recover significantly, production can recommence after assessing the pressure build-up. Fluid level monitored regularly.

Exploration Application Areas, Northern Territory

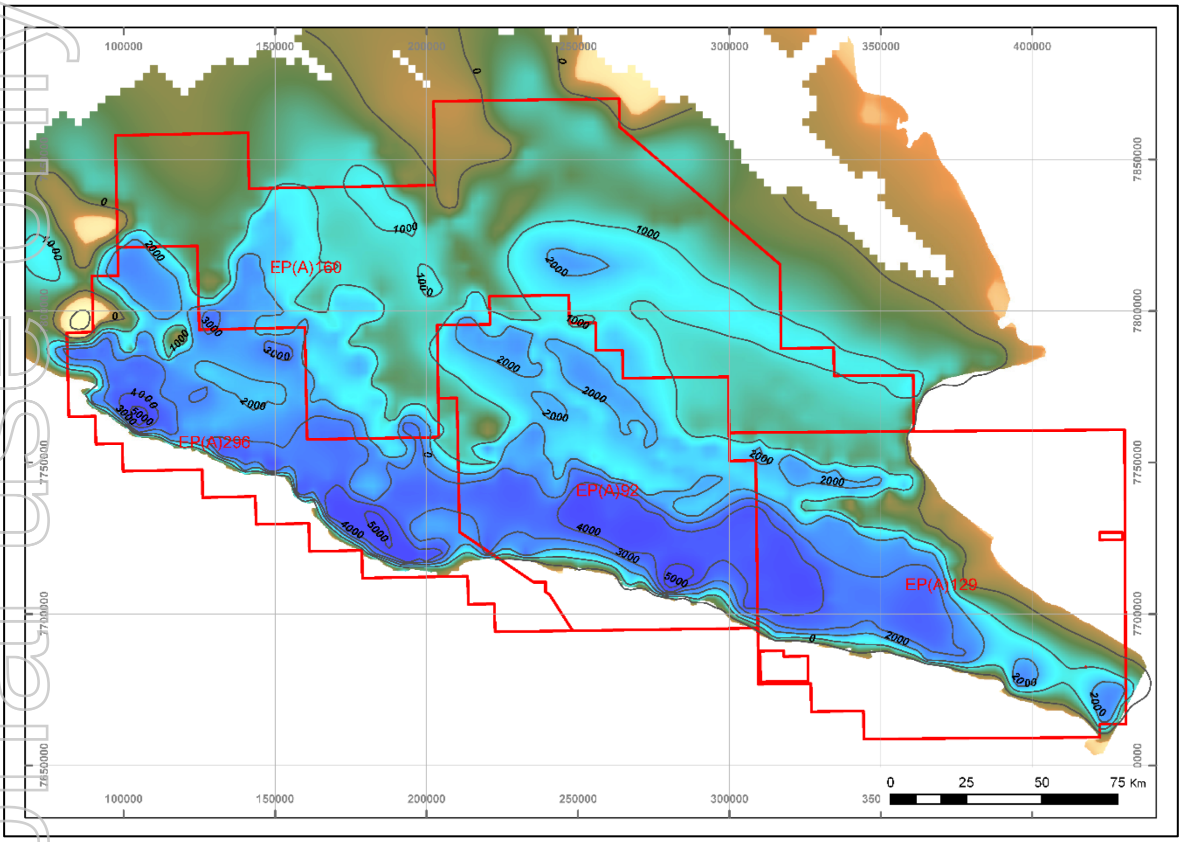
Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 88)

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 program 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

Reserves and Resource Volumes for Gas (Units: PJ)[1]

	1P	2P	3P	1C	2C	3C
Palm Valley[1]	17.7	23.6	—	—	29.7	—
Dingo[1]	10.3	33.2	—	—	22.7	—
Mereenie[2]	61.9	75.0	81.7	56.6	91.2	106.8
Total	**89.9**	**131.8**	**81.7**	**56.6**	**143.6**	**106.8**

1 *NSAI Reserves report and ASX release July 2015, Reserves and Resources are 100% Net to Central.*
2 *Mereenie Reserves are from YE2015 with Reserves and Resources being 50% Net to Central*

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

There were no significant changes in the state of affairs of the Group during the financial year.

EVENTS SINCE THE END OF THE FINANCIAL YEAR

On 10 August 2017 the Company announced a $27 million equity raising to support the gas acceleration programme. The equity raising comprised a placement to institutional and sophisticated investors of $9.2 million and a fully underwritten 5 for 12 non-renounceable entitlement offer to raise approximately $18.0 million. The equity raising has been successfully concluded resulting in net proceeds of approximately $25.4 million after costs.

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.

INFORMATION ON DIRECTORS

Robert Hubbard FCA BA (Hons)

Independent Non-executive Director

Mr Hubbard was a partner with PricewaterhouseCoopers for 22 years specialising in audit, deals and valuation advice, predominantly in the resources sector. He has highly developed financial skills and business experience, including managing significant capital and growth agendas, risk management, corporate governance and valuations.

Mr Hubbard is a non-executive director of Bendigo and Adelaide Bank Limited, Primary Health Care Limited and Chairman of Orocobre Limited. Within the last three years, he has not been a director of any other listed public company.

Richard I 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 (Hons), MBA (Dist)

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 and resources 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. 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 maker 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 (SIAS), recognizing 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. He was appointed Non Executive Director of Sino Australia Oil and Gas in March 2014, resigning in 2015.

Within the last three years, Mr Gasteen has not been a director of any other listed public

Prof. Peter S Moore BSc (Hons 1), MBA, PhD

Independent Non-executive Director

Prof. Peter S 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 in Houston and from 1998 until his retirement in 2013, with Woodside Energy Ltd.

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.

Prof. Moore is a Non-executive Director of Carnarvon Petroleum Limited and Beach Energy Limited (since July 2017), Executive Director, Strategic Engagement for the Curtin Business School (part time), Chair of ESWA (Earth Sciences WA), member of Curtin University's Faculty of Science and Engineering Advisory Council and Curtain Business School Advisory Council. Within the last three years, Prof. Moore has not been a director of any other listed public company.

John Thomas (Tom) Wilson BSc (Zoology), MSc (Geology)

Independent Non-executive Director

Mr Wilson was appointed a director to the Central Board on 31 March 2014 and retired from the Central Board on 15 July 2016.

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 number of directors' meetings held where the director was eligible to attend and the number of meetings attended by each of the directors of the Company during the financial year were:

	Full Meeting of Directors		Audit & Risk Committee		Remuneration & Nominations Committee	
	Eligible	Attended	Eligible	Attended	Eligible	Attended
Robert Hubbard	23	23	4	4	3	3
Richard Cottee	23	23	—	—	—	—
Wrixon Gasteen	23	22	4	4	3	3
Peter Moore	23	23	4	4	3	3

REALISED REMUNERATION OF DIRECTORS AND KEY MANAGEMENT PERSONNEL FOR THE 2017 YEAR

The directors consider the remuneration information contained within the tables presented in the statutory remuneration report (pages 20 to 29) may give a distorted view of the true remuneration realised by the directors and key management personnel for the 2017 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	75,000	—	15,510	—	7,125	97,635	100%	—	97,635
Robert Hubbard	110,000	—	—	—	10,450	120,450	100%	—	120,450
J Thomas Wilson[2]	2,837	—	—	—	—	2,837	100%	—	2,837
Peter Moore	80,000	—	—	—	7,600	87,600	100%	—	87,600
Sub-total	267,837	—	15,510	—	25,175	308,522	100%	—	308,522

Executive Directors & Key Management Personnel	Salary / fees $	STIP $	Non-monetary benefits[1] $		Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Richard Cottee	576,537	54,400	7,738	—	19,616	658,291	100%	—	658,291
Michael Herrington	477,722	22,500	17,577	—	36,109	553,908	100%	—	553,908
Daniel White	392,098	16,000	3,618	—	33,078	444,794	100%	—	444,794
Leon Devaney	404,155	37,100	4,305	—	28,163	473,723	100%	—	473,723
Sub-total	1,850,512	130,000	33,238	—	116,966	2,130,716	100%	—	2,130,716
Total Remuneration	**2,118,349**	**130,000**	**48,748**	—	**142,141**	**2,439,238**	**100%**	—	**2,439,238**

1 *Fringe benefits include loan fringe benefits relating to deferred director option fees and employee car parking fringe benefits*
2 *Mr Wilson resigned as Director on 15 July 2016*

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 83 employees at 30 June 2017 (83 at 30 June 2016).

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	
	2017	2016
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	17,615	17,628
Excise consulting services	—	4,500
Other tax related services	19,622	19,019
	37,237	**41,147**
(ii) Other services		
Magellan transaction due diligence		—
Mereenie transaction due diligence	—	90,999
Technical accounting advice on major transactions	—	27,181
Employee related services	—	—
	—	**118,180**
Total remuneration for non-audit services	**37,237**	**159,327**

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 30.

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 2017 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

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
Richard Cottee	Managing Director and Chief Executive Officer
Wrixon Gasteen	Non-executive Director
Peter Moore	Non-executive Director
J Thomas Wilson	Non-executive Director (to 15 July 2016)

Other Key Management Personnel

Leon Devaney	Chief Financial Officer
Michael Herrington	Chief Operating Officer
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 2017, 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 2018.
Nil LTIP Vesting	There were no awards that vested under the Long Term Incentive Plan during fiscal year 2017..

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 did not engage a remuneration consultant.

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 2017, 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 EMT (Executive Management Team) 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:

1. Share Rights can only be dealt with the earlier of three years or on termination of employment; and
2. No performance conditions apply.

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 KPI 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 2016/17.

Key terms and conditions

The 2016/2017 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 KPIs 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	10%	10%
Departmental KPIs	40%	30%
Individual KPIs	20%	30%

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

The 2016/2017 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 2016/2017 Plan Year STIP.

Corporate KPIs included:

OBJECTIVE	WEIGHTING	100%	75%	50%
New Revenue: Project(s) to increase revenue ($2 million or more NPV)	33%	Board approved FID at least 1 project that results in an additional signed agreement	Substantially completed 1 or more proposals for projects for pre-feasibility Board approval	Materially progressed 1 or more proposals for projects for pre-feasibility Board approval
Budgetary control	33%	Ensure no expenditure occurs outside of any approved budget without Board approval, and costs are minimised whilst still achieving the approved scope of work		
Pipeline Tariffs *	33%	$2.00 per GJ below reference	$1.50 per GJ below reference	$0.75 cents per GJ below reference

* Process to introduce economic regulation capacity trading 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 KPI's 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 18.

Table 1: Remuneration of Directors and Key Management Personnel

		SHORT-TERM			POST-EMPLOYMENT		LONG-TERM BENEFITS	SHARE-BASED PAYMENTS		
		Salary / fees $	Cash STI[7] $	Non-monetary benefits[1] $	Superannuation contributions $	Termination Benefits $	LSL $	(At Risk) Options & Rights[4] $	Total $	Value of Options& Rights as Proportion of Remuneration %
Non-Executive Directors										
Andrew Whittle[2]	2017	—	—	—	—	—	—	—	—	—
	2016	12,008	—	17,800	28,516	—	—	74,759	133,083	56%
Wrixon Gasteen	2017	75,000	—	15,510	7,125	—	—	9,451	107,086	9%
	2016	82,500	—	19,777	7,837	—	—	73,613	183,727	40%
Robert Hubbard	2017	110,000	—	—	10,450	—	—	—	120,450	0%
	2016	115,500	—	—	10,972	—	—	—	126,472	0%
J Thomas Wilson[3]	2017	2,837	—	—	—	—	—	—	2,837	0%
	2016	68,250	—	—	—	—	—	—	68,250	0%
Peter Moore	2017	80,000	—	—	7,600	—	—	—	87,600	0%
	2016	89,333	—	—	8,487	—	—	—	97,820	0%
Sub-total	2017	267,837	—	15,510	25,175	—	—	9,451	317,973	3%
	2016	367,591	—	37,577	55,812	—	—	148,372	609,352	24%
Executive Directors and Other Key Management Personnel										
Richard Cottee	2017	607,706	51,888	7,738	19,616	—	18,970	1,445,743	2,151,661	67%
	2016	609,146	54,400	10,574	19,308	—	9,391	1,543,173	2,245,992	69%
Michael Herrington	2017	474,166	36,103	17,577	36,109	—	11,006	139,875	714,836	20%
	2016	468,514	22,500	26,418	37,548	—	10,919	124,022	689,921	18%
Daniel White	2017	407,527	28,440	3,618	33,078	—	7,525	111,084	591,272	19%
	2016	396,947	16,000	7,389	33,048	—	8,594	37,119	499,097	7%
Leon Devaney	2017	412,005	39,346	4,305	28,163	—	9,082	91,951	584,852	16%
	2016	419,561	37,100	8,629	31,837	—	11,647	46,410	555,184	8%
Robbert Willink[5]	2017	—	—	—	—	—	—	—	—	—
	2016	154,085	—	—	17,725	—	5,136	7,752	184,698	4%
Michael Bucknill[6]	2017	—	—	—	—	—	—	—	—	—
	2016	218,666	—	7,389	20,599	116,923	(6,820)	(4,848)	351,909	—
Sub-total	2017	1,901,404	155,777	33,238	116,966	—	46,583	1,788,653	4,042,621	44%
	2016	2,266,919	130,000	60,399	160,065	116,923	38,867	1,753,628	4,526,801	39%
Total Remuneration	**2017**	**2,169,241**	**155,777**	**48,748**	**142,141**	**—**	**46,583**	**1,798,104**	**4,360,594**	**41%**
	2016	**2,634,510**	**130,000**	**97,976**	**215,877**	**116,923**	**38,867**	**1,902,000**	**5,136,153**	**37%**

[1] *Represents fringe benefits tax.*
[2] *Mr Whittle resigned as director 2 November 2015.*
[3] *Mr Wilson resigned as director 15 July 2016*
[4] *The valuation date for options issued to FEP was 19 July 2012 and to directors was 29 November 2012. Negative amounts represent revisions to estimates and/or cancelled and forfeited options.*
[5] *Mr Willink is not considered a part of Key Management Personnel for the 2017 year*
[6] *Mr Bucknill's position was made redundant 26 February 2016.*
[7] *STI's are unpaid at the end of the the year. Amounts are shown in respect of the performance year to which they relate. 2016 comparatives have been amended to present these on a consistent basis.*

The fair values of deferred share rights granted during 2017 were also 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.

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%

The values disclosed for 2016 are the portions of the fair values applicable to and recognised in this reporting period. The following factors and assumptions were used in determining the fair value of options at grant date:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER OPTION	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
14 Oct 15	05 Jan 21	$0.1460	Nil	$0.190	80%	2.05%	0.00%
22 Dec 15	05 Jan 21	$0.0845	Nil	$0.165	87%	2.22%	0.00%
22 Dec 15	09 Feb 21	$0.1230	Nil	$0.165	87%	2.22%	0.00%

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

		NUMBER OF RIGHTS GRANTED	GRANT DATE	AVERAGE FAIR VALUE AT GRANT DATE	AVERAGE EXERCISE PRICE PER RIGHT	EXPIRY DATE	NUMBER OF RIGHTS VESTED	PROPORTION OF RIGHTS VESTED
Non-Executive Directors								
Andrew Whittle[1]	2017	—	—	—	—	—	—	—
	2016	—	—	—	—	—	—	—
Wrixon Gasteen	2017	—	—	—	—	—	—	—
	2016	—	—	—	—	—	—	—
Robert Hubbard	2017	—	—	—	—	—	—	—
	2016	—	—	—	—	—	—	—
J Thomas Wilson[2]	2017	—	—	—	—	—	—	—
	2016	—	—	—	—	—	—	—
Peter Moore	2017	—	—	—	—	—	—	—
	2016	—	—	—	—	—	—	—
Executive Directors and Other Key Management								
Richard Cottee	2017	3,202,983	16 Nov 16	$0.151	$0.000	08 Dec 22	—	—
	2016	1,913,873	22 Dec 15	$0.123	$0.000	09 Feb 21	—	—
	2016	193,031	22 Dec 15	$0.085	$0.000	05 Jan 21	—	—
Michael Herrington	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	—	—
	2016	930,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
Daniel White	2017	1,289,666	16 Nov 16	$0.151	$0.000	08 Dec 22	—	—
	2016	770,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
Leon Devaney	2017	1,311,533	20 Oct 16	$0.106	$0.000	08 Dec 22	—	—
	2016	783,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
Michael Bucknill[3]	2017	—	—	—	—	—	—	—
	2016	640,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—

[1] Mr Whittle resigned 2 November 2015.
[2] Mr Wilson resigned as director 15 July 2016.
[3] Mr Bucknill's position was made redundant 26 February 2016. All Rights were subsequently cancelled.

Table 3: Shareholdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF OPTIONS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Wrixon Gasteen	2017	136,473	N/A	—	—	—	N/A	136,473
	2016	97,000	N/A	39,473	—	—	N/A	136,473
Robert Hubbard	2017	298,947	N/A	—	—	—	N/A	298,947
	2016	120,000	N/A	178,947	—	—	N/A	298,947
J Thomas Wilson[1]	2017	—	N/A	—	—	—	N/A	—
	2016	—	N/A	—	—	—	N/A	—
Peter Moore	2017	—	—	—	—	—	N/A	—
	2016	—	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2017	632,438	N/A	—	—	(60,609)[2]	N/A	571,829
	2016	436,383	N/A	196,055	—	—	N/A	632,438
Michael Herrington	2017	250,000	N/A	—	—	—	N/A	250,000
	2016	250,000	N/A	—	—	—	N/A	250,000
Daniel White	2017	288,000	N/A	—	—	—	N/A	288,000
	2016	288,000	N/A	—	—	—	N/A	288,000
Leon Devaney	2017	210,000	N/A	—	—	—	N/A	210,000
	2016	210,000	N/A	—	—	—	N/A	210,000

1 *Mr Wilson resigned as director 15 July 2016.*
2 *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 year.*

Table 4: Option Holdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	OPTIONS EXERCISED	GRANTED AS REMUNERATION	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors							
Wrixon Gasteen	2017	666,666	—	—	(666,666)	N/A	—
	2016	1,000,000	—	—	(333,334)	N/A	666,666
Robert Hubbard	2017	—	—	—	—	N/A	—
	2016	—	—	—	—	N/A	—
J Thomas Wilson[1]	2017	—	—	—	—	N/A	—
	2016	—	—	—	—	N/A	—
Peter Moore	2017	—	—	—	—	N/A	—
	2016	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel							
Richard Cottee[2]	2017	24,900,773	—	—	—	N/A	24,900,773
	2016	34,584,407	—	—	(9,683,634)	N/A	24,900,773
Michael Herrington	2017	1,950,000	—	—	(1,950,000)	N/A	—
	2016	2,250,000	—	—	(300,000)	N/A	1,950,000
Daniel White	2017	760,000	—	—	(760,000)	N/A	—
	2016	1,493,334	—	—	(733,334)	N/A	760,000
Leon Devaney	2017	504,000	—	—	(504,000)	N/A	—
	2016	1,064,000	—	—	(560,000)	N/A	504.000

1 *Mr Wilson retired, effective 15 July 2016.*
2 *Remaining options held at 30 June 2017 expire 15 November 2017*

The vesting profile for options held at the end of the year was as follows:

		HOLDINGS AT END OF YEAR	VESTED DURING THE YEAR	EXERCISABLE AT END OF YEAR
Non-Executive Directors				
Wrixon Gasteen	2017	—	—	—
	2016	666,666	—	—
Executive Directors and Other Key Management Personnel				
Richard Cottee[1]	2017	24,900,773	—	—
	2016	24,900,773	—	—
Michael Herrington	2017	—	—	—
	2016	1,950,000	—	—
Daniel White	2017	—	—	—
	2016	760,000	—	—
Leon Devaney	2017	—	—	—
	2016	504,000	—	—

[1] *Remaining options held at 30 June 2017 expire 15 November 2017*

For each grant of options included in the Tables 1 to 4 above, the percentage of the grant that was vested and the percentage that was forfeited, are set out below. The options vest over a range of time frames provided the vesting conditions are met. No options will vest if the conditions are not satisfied, hence the minimum value of the option yet to vest is Nil. The maximum value of the options yet to vest has been determined as the amount of the grant date fair value of the options that is yet to be expensed.

NAME	SHARE BASED COMPENSATION BENEFITS (OPTIONS)				
	Year Granted	Vested %	Forfeited %	Financial Years in which Options may Vest	Maximum Value of Grant yet to Vest $
Wrixon Gasteen	2013	33	67	—	—
Richard Cottee	2013	28	—	2013 to 2018	439,591
Michael Herrington	2014	—	100	—	—
	2013	33	67	—	—
Daniel White	2015	—	100	—	—
	2014	100	—	—	—
	2012	100	—	—	—
Leon Devaney	2015	—	100	—	—
	2014	100	—	—	—

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 5: 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	2017	2,104,904	3,202,983	—	—	5,307,887
	2016	—	2,104,904	—	—	2,104,904
Michael Herrington	2017	930,000	1,956,237	—	—	2,886,237
	2016	—	930,000	—	—	930,000
Daniel White	2017	1,100,000	1,289,666	—	—	2,389,666
	2016	330,000	770,000	—	—	1,100,000
Leon Devaney	2017	1,061,571	1,311,533	—	—	2,373,104
	2016	278,571	783,000	—	—	1,061,571

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

- The term of the agreement expires 29 June 2018.
- Mr Cottee's base salary is presently $587,491 per annum. In addition, superannuation at 9.5% subject to the statutory limit 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, Executive Director and Chief Operating Officer

- The term of the agreement expires 29 January 2019.
- Mr Herrington's base salary is presently $476,178 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.

Leon Devaney, Chief Financial Officer

- The term of the agreement expires 16 November 2018.
- Mr Devaney's base salary is presently $402,509 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.

Daniel White, Group General Counsel and Company Secretary

- The Company entered into a new agreement expiring 30 November 2021.
- Mr White's base salary is presently $392,703 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 2017.

BOARD FEES (PER ANNUM)	
Chairman	$95,000.00
Non-Executive Director	$65,000.00

COMMITTEE FEES (PER ANNUM)		
Audit & Risk	Chair	$10,000.00
	Member	$5,000.00
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:

Richard Cottee
Managing Director
Brisbane

25 September 2017

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2017, 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
25 September 2017

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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 2017 Corporate Governance Statement is dated as at 30 June 2017 and reflects the corporate governance practices in place throughout the 2017 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

CONTENTS

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 5 to 29. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 25 September 2017. 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 2017

	NOTE	2017 $	2016 $
Revenue from the sale of goods	23(a)	24,794,145	22,642,569
Other revenue from customers	23(a)	—	1,220,000
Cost of sales		(15,701,690)	(14,060,704)
Gross profit		9,092,455	9,801,865
Other income	2	3,114,038	259,939
Share based employment benefits	31(d)	(2,251,024)	(2,235,544)
General and administrative expenses		(1,946,659)	(505,674)
Depreciation and amortisation	3(a)	(7,780,576)	(8,404,153)
Employee benefits and associated costs		(5,658,990)	(4,478,454)
Exploration expenditure		(1,901,382)	(4,025,627)
Restructure of future contingent commitments	3(b)	—	(1,725,000)
Finance costs	3(a)	(7,812,071)	(8,290,599)
Restatement of financial liabilities	3(a)	(9,493,259)	—
Impairment expense	3(a)	(89,013)	(1,437,045)
Loss before income tax		(24,726,481)	(21,040,292)
Income tax credit	4	—	—
Loss for the year		(24,726,481)	(21,040,292)
Other comprehensive loss for the year, net of tax		—	—
Total comprehensive loss for the year		(24,726,481)	(21,040,292)
Total comprehensive loss attributable to members of the parent entity		**(24,726,481)**	**(21,040,292)**
Basic and diluted loss per share (cents)	22	(5.71)	(5.16)

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 30 JUNE 2017

	NOTE	2017 $	2016 $
ASSETS			
Current assets			
Cash and cash equivalents	6	5,478,140	15,115,699
Trade and other receivables	7	4,996,216	3,787,278
Inventories	8	3,273,014	3,592,561
Total current assets		13,747,370	22,495,538
Non-current assets			
Property, plant and equipment	9	106,816,359	113,783,254
Exploration assets	10	8,898,767	8,898,767
Intangible assets	11	82,157	82,393
Other financial assets	12	2,501,947	2,208,624
Goodwill	13	3,906,270	3,906,270
Total non-current assets		122,205,500	128,879,308
Total assets		**135,952,870**	**151,374,846**
LIABILITIES			
Current liabilities			
Trade and other payables	14	3,239,168	6,896,389
Deferred revenue	15	2,714,334	2,714,334
Interest-bearing liabilities	16	3,859,747	3,784,194
Other financial liabilities	18	38,600	—
Provisions	17	3,161,454	3,766,713
Total current liabilities		13,013,303	17,161,630
Non-current liabilities			
Trade and other payables	14	—	2,621,694
Deferred revenue	15	5,283,741	1,253,074
Interest-bearing liabilities	16	78,310,007	81,916,860
Other financial liabilities	18	21,914,537	11,765,271
Provisions	17	23,389,129	20,138,707
Total non-current liabilities		128,897,414	117,695,606
Total liabilities		**141,910,717**	**134,857,236**
Net assets		**(5,957,847)**	**16,517,610**
EQUITY			
Contributed equity	19	172,301,532	172,301,532
Reserves	20	21,841,455	19,590,431
Accumulated losses	21	(200,100,834)	(175,374,353)
Total equity		**(5,957,847)**	**16,517,610**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2017

	CONTRIBUTED EQUITY $	RESERVES $	ACCUMULATED LOSSES $	TOTAL $
Balance at 1 July 2015	**160,785,182**	**16,695,379**	**(154,334,061)**	**23,146,500**
Total loss for the year	—	—	(21,040,292)	(21,040,292)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(21,040,292)	(21,040,292)
Transactions with owners in their capacity as owners				
Share based payments	—	2,235,544	—	2,235,544
Options issued for financing	—	659,508	—	659,508
Share and option issues	12,250,990	—	—	12,250,990
Share issue costs	(734,640)	—	—	(734,640)
	11,516,350	2,895,052	—	14,411,402
Balance at 30 June 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)**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOW

FOR THE YEAR ENDED 30 JUNE 2017

	NOTE	**2017** **$**	2016 $
Cash flows from operating activities			
Receipts from customers		27,628,945	26,674,618
Interest received		165,581	239,221
Other income		667,355	4,073,057
Interest and borrowing costs		(6,347,719)	(7,319,016)
Payments for restructuring future contingent commitments	3(b)	—	(1,725,000)
Payments to suppliers and employees (inclusive of GST)[1]		(22,348,163)	(23,435,656)
Net cash outflow from operating activities	27	(234,001)	(1,492,776)
Cash flows from investing activities			
Payments for property, plant and equipment		(1,297,122)	(1,831,972)
Payments for interest in Mereenie Joint Venture		(3,342,446)	(47,073,161)
Proceeds from sale of property, plant and equipment		99,591	354,360
(Acquisition)/Redemption of security deposits and bonds		(863,581)	101,759
Net cash outflow from investing activities		(5,403,558)	(48,449,014)
Cash flows from financing activities			
Proceeds from the issue of shares and options		—	11,516,350
Proceeds from borrowings and other financing arrangements		—	53,025,000
Repayment of borrowings[1]		(4,000,000)	(3,000,000)
Net cash (outflow)/inflow from financing activities		(4,000,000)	61,541,350
Net increase/(decrease) in cash and cash equivalents		**(9,637,559)**	**11,599,560**
Cash and cash equivalents at the beginning of the financial year		**15,115,699**	**3,516,139**
Cash and cash equivalents at the end of the financial year	6	**5,478,140**	**15,115,699**

[1] *Cash outflows in respect of the 2016 year for insurance premium funding arrangements have been reclassified from financing activities to operating activities to reflect the underlying nature of the payments, consistent with the cash flows presented for the 2017 year..*

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 $24,726,481, a net cash outflow from operations of $234,001 and an overall net liability position of $5,957,847. However, in June 2017 the Group commenced sales under a 5 year Gas Sales Agreement to EDL NGD (NT) Pty Ltd and in September 2017 the Group announced completion of capital raising initiatives which collectively generated $25.4 million of net cash proceeds (after costs). Management are confident that these events are sufficient to allow the Group to meet its debts as and when they fall due.

The net liability position of $5,957,847 has arisen due to a combination of factors, one of which relates to the Macquarie Bank Limited Gas Sale and Pre-payment Agreement entered into in May 2016 which has resulted in the recognition of a liability as discussed in Note 3(b). At the time of settlement of the liability, it will be satisfied by the physical delivery of gas from existing 1P reserves 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 2016 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.

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

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 (continued)

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 prices and the terms of individual agreements.

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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation (continued)

(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 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 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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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(b)). 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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 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.

(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, and all development drilling and other subsurface expenditure completed. 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

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

(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. 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. Amortisation is not charged on costs carried forward in respect of areas of interest in the development phase until production commences.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 (including directors) 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 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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(w) Earnings Per Share (continued)

(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 2015. 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. The Group has concluded these standards and interpretations are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

(a) AASB 15 Revenue from contracts with customers

The AASB has issued a new standard for the recognition of revenue. This will replace AASB 118 which covers contracts for goods and services and AASB 111 which covers construction contracts. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer – so the notion of control replaces the existing notion of risks and rewards. The new standard is mandatory for financial years commencing on or after 1 January 2018.

Management has undertaken an initial assessment of the effects of applying the new standard on the group's financial statements and does not expect the changes will have any material impact on the way revenue is currently recognised.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations (continued)

(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 not applicable until 1 January 2018 but is available for early adoption.

Whilst the Group has not yet undertaken a detailed assessment of the changes, it does not currently expect any 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, which is not expected to have any impact on the Group.

(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 $1,869,643. The Group has not yet determined to what extent these commitments will result in the recognition of an asset and a liability for future payments and how 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. The group does not expect to adopt the standard early.

2. OTHER INCOME

	2017 **$**	2016 $
Interest	149,481	259,439
Research and development refunds (a)	634,167	—
Forgiveness of amounts due under Joint ventures (b)	2,017,203	—
Sale of exploration permits	280,000	—
Other income	33,187	500
Total other income	**3,114,038**	**259,939**

(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 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	2017 $	2016 $
Depreciation			
Buildings		349,297	290,229
Producing assets		2,553,914	2,653,307
Plant and equipment		4,808,986	5,412,754
Leasehold improvements		41,183	27,812
Total depreciation		7,753,380	8,384,102
Amortisation			
Software		27,196	20,051
Impairment expense	3(b)	89,013	1,437,045
Other operating expenses	3(b)	—	1,725,000
Rental expense relating to operating leases – Minimum lease payments		518,088	984,026
Restatement of financial liabilities	3(b)	9,493,259	—
Finance costs			
Interest charge on Macquarie debt facility		6,328,742	6,687,983
Interest paid to other suppliers		18,737	20,545
Interest on other financial liabilities		533,774	40,271
Borrowing costs on Macquarie and other debt facilities		240	637,761
Amortisation of deferred finance costs		485,725	510,734
Accretion charge		444,853	393,305
		7,812,071	8,290,599

(b) Individually significant items

Impairment of Assets

Oil and gas producing assets

During the 2016 year impairment expense totaling $37,045 was recorded in relation to final adjustments made to the capital costs of the oil producing assets in the Amadeus Basin which were fully impaired in the prior financial year.

Property

Impairment expense amounting to $89,013 was recorded in respect of property assets held as the part of the Southern Georgina Joint operations following Total's decision to withdraw from Joint Operations.

There was no impairment of any property assets during the 2016 year.

3. EXPENSES (CONTINUED)

Exploration assets

There was no impairment of exploration assets during the current financial year.

During the 2016 year the following exploration permits previously classified as Assets Held for Sale were impaired to their recoverable amounts:

EP97 was impaired by $1,273,333 following an unsuccessful divestment process and submission of an application to surrender the permit in June 2016. No further costs remain capitalised in respect of this permit.

EP107 was impaired by $126,667 following an unsuccessful divestment process and on the basis that there is insufficient prospectivity to warrant any further activities in the permit. No further costs remain capitalised in respect of this permit.

Restatement of financial liabilities

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 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 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. The liability under the Pre-sale agreement with MBL will, at the time, be satisfied by the physical delivery of gas from existing 1P reserves 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.

Restructure of future contingent commitments

In the 2016 year, a one-off amount of $1,725,000 was expensed relating to the costs of restructuring future contingent commitments and associated transaction costs. The transaction had the effect of removing Central's net exposure to the Mereenie Production Bonus (refer Note 29(a)(iii)).

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.

	2017 $	2016 $
(a) Income tax expense		
Current tax	—	—
Deferred tax	—	—
Income tax expense	—	—

4. INCOME TAX (CONTINUED)

(b) Numerical reconciliation of income tax expense and prima facie tax benefit

	2017 $	2016 $
Loss before income tax expense	(24,726,481)	(21,040,292)
Prima facie tax benefit at 30% (2016: 30%)	7,417,944	6,312,088
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(147,002)	66,390
Research and development expenditure	—	—
Share based payments	(675,307)	(670,663)
Non-assessable income (R&D Refund)	190,250	—
Sub-total	6,785,885	5,707,815
Under provision in prior year	—	—
Deferred tax assets not recognised	(6,785,885)	(5,707,815)
Recognition of previously unrecognised DTA	—	—
Income tax expense	—	—

(c) Amounts recognised directly in equity

	2017 $	2016 $
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	—	220,392
Deferred tax assets not recognised	—	(220,392)
Net amounts recognised directly in equity	—	—

(d) Tax Losses

	2017 $	2016 $
Unutilised tax losses for which no deferred tax asset has been recognised	120,670,253	112,459,194
Potential tax benefit at 30%	36,201,076	33,737,758

4. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2017 $	2016 $
Deferred tax assets		
Provisions and accruals	8,073,231	7,230,559
Financial liabilities	3,020,191	12,081
Future deductible expenditure	517,500	517,500
Blackhole expenditure	633,119	349,265
Borrowing costs	130,099	216,876
PRRT	222,245,877	201,315,062
Unutilised losses	46,462,857	42,834,869
Total deferred tax assets before set-offs	281,082,874	252,476,212
Set-off of deferred tax liabilities pursuant to set-off provisions	(12,050,541)	(10,720,341)
Net deferred tax assets not recognised	**269,032,333**	**241,755,871**
Movements		
Opening balance at 1 July	10,720,341	6,993,154
(Charged) / Credited to the income statement	1,330,200	3,727,187
Closing balance at 30 June	12,050,541	10,720,341
Deferred tax assets to be recovered after more than 12-months	10,849,394	9,531,395
Deferred tax assets to be recovered within 12-months	1,201,147	1,188,946
	12,050,541	10,720,341
Deferred tax liabilities		
Acquired income	4,007	16,177
Capitalised exploration	450,254	437,254
Property, plant and equipment	9,296,490	8,643,680
PRRT	2,299,790	1,623,230
Total deferred tax assets before set-offs	12,050,541	10,720,341
Set-off of deferred tax liabilities pursuant to set-off provisions	(12,050,541)	(10,720,341)
Net deferred tax liabilities	—	—
Movements		
Opening balance at 1 July	10,720,341	6,993,154
Charged / (Credited) to the income statement	1,330,200	3,727,187
Closing balance at 30 June	12,050,541	10,720,341
Deferred tax liabilities to be recovered after more than 12-months	12,046,535	10,704,164
Deferred tax liabilities to be recovered within 12-months	4,006	16,177
	12,050,541	10,720,341

5. REMUNERATION OF AUDITORS

	2017 $	2016 $
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	155,130	175,654
(ii) Taxation services		
Income Tax compliance	17,615	17,628
Excise consulting services	—	4,500
Other tax related services	19,622	19,019
	37,237	41,147
(iii) Other services		
Mereenie transaction due diligence	—	90,999
Technical accounting advice on major transactions	—	27,181
	—	118,180
Total remuneration of PwC	**192,367**	**334,981**

6. CASH AND CASH EQUIVALENTS

	2017 $	2016 $
Cash at bank and in hand	5,478,140	15,115,699
Made up as follows:		
Corporate (a)	5,081,168	14,439,416
Joint arrangements (b)	396,972	676,283
	5,478,140	15,115,699

(a) $1,421,848 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2016: $4,981,343), 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

	2017 $	2016 $
Current		
Trade receivables	485,337	471,752
Accrued income (a)	3,711,267	2,524,009
Accrued research and development refund	—	—
Other receivables	25,417	25,883
GST receivables	—	—
Prepayments	774,195	765,634
	4,996,216	**3,787,278**

(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	219,375	238,947
Spare parts and consumables	2,292,533	2,592,508
Drilling materials and supplies at cost	761,106	761,106
	3,273,014	**3,592,561**

9. PROPERTY, PLANT AND EQUIPMENT

	FREEHOLD LAND AND BUILDINGS $	PRODUCING ASSETS $	ASSETS IN DEVELOPMENT $	PLANT AND EQUIPMENT $	TOTAL $
Year ended 30 June 2016					
Opening net book amount	260,924	35,003,337	—	23,313,154	58,577,415
Additions	—	—	—	1,411,501	1,411,501
Changes to rehabilitation estimates	—	1,450,511	—	—	1,450,511
Mereenie assets acquisition	3,558,479	45,087,956	—	12,112,947	60,759,382
Disposals and write offs	—	—	—	(69)	(69)
Impairment	—	—	—	(31,384)	(31,384)
Depreciation charge	(290,229)	(2,653,307)	—	(5,440,566)	(8,384,102)
Closing net book amount	**3,529,174**	**78,888,497**	—	**31,365,583**	**113,783,254**
At 30 June 2016					
Cost	3,819,403	84,669,001	—	44,130,961	132,619,365
Accumulated depreciation	(290,229)	(5,780,504)	—	(12,765,378)	(18,836,111)
Net book amount	**3,529,174**	**78,888,497**	—	**31,365,583**	**113,783,254**
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**

10. EXPLORATION ASSETS

	2017 $	2016 $
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

	2017 $	2016 $
SOFTWARE		
At the beginning of the year		
Cost	358,365	262,311
Accumulated amortisation	(275,972)	(250,259)
Net book value	**82,393**	**12,052**
Movements for the year		
Opening net book amount	82,393	12,052
Additions	27,014	96,053
Disposals and write offs	(54)	—
Impairment	—	(5,661)
Amortisation	(27,196)	(20,051)
Closing net book amount	**82,157**	**82,393**
At the end of the year		
Cost	379,615	358,365
Accumulated amortisation	(297,458)	(275,972)
Net book value	**82,157**	**82,393**

12. OTHER FINANCIAL ASSETS

Security bonds on exploration permits and rental properties	**2,501,947**	**2,208,624**

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.

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

2017	Producing Assets
Sales volumes	Contracted
Sales price (% annual growth rate)	2.50%
Operating costs (% annual growth rate)	2.50%
Pre-tax discount rate (%)	16.03%

13. GOODWILL (CONTINUED)

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

Assumption	Approach used to determining values
Sales volume	Annual contracted Natural Gas quantities (subject to Take or Pay clauses where applicable). 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 sale volumes. No incremental revenue or costs savings are assumed as a result of this expenditure.
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

	2017 $	2016 $
Current		
Trade payables	2,552,400	2,882,715
Other payables	492	234,650
Mereenie acquisition amounts due	—	3,358,590
Accruals	686,276	420,434
	3,239,168	**6,896,389**
Non-Current		
Southern Georgina joint arrangement contribution	—	2,621,694
	—	**2,621,694**

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:

	2017 $	2016 $
Current		
Available to be taken within 12-months	2,714,334	2,714,334
	2,714,334	**2,714,334**
Non-Current		
Available to be taken after 12-months	5,283,741	1,253,074
	5,283,741	**1,253,074**

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.

16. INTEREST BEARING LIABILITIES

	2017 $	2016 $
(a) Interest bearing liabilities (current)[1]		
Debt facilities	3,859,747	3,784,194
	3,859,747	**3,784,194**
(b) Interest bearing liabilities (non-current)[1]		
Debt facilities	78,310,007	81,916,860
	78,310,007	**81,916,860**

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

17. PROVISIONS

	2017			2016		
	Current $	Non-current $	Total $	Current $	Non-current $	Total $
Employee entitlements (a)	3,059,075	516,369	3,575,444	2,466,246	394,148	2,860,394
Onerous contracts (b)	—	—	—	199,076	82,400	281,476
Restoration and rehabilitation (c)	102,379	21,160,338	21,262,717	357,510	19,662,159	20,019,669
Joint Venture production over-lift (d)	—	1,712,422	1,712,422	743,881	—	743,881
Other	—	—	—	—	—	—
	3,161,454	**23,389,129**	**26,550,583**	**3,766,713**	**20,138,707**	**23,905,420**

(a) 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:

	2017 $	2016 $
Current leave obligations expected to be settled after 12-months	706,408	662,419

(b) The provision for onerous contracts related to operating lease commitments on the rental of office space at 167 Eagle Street, Brisbane which expired during the 2017 year.

(c) 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.

(d) 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.

17. PROVISIONS (CONTINUED)

Movements in Provisions

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

2017	Employee Entitlements $	Onerous Contracts $	Restoration & Rehabilitation $	Other $	Total $
Carrying amount at start of year	**2,860,394**	**281,476**	**20,019,669**	**743,881**	**23,905,420**
Change in provision charged to property, plant and equipment	—	—	(19,869)	—	(19,869)
Additional provisions charged to profit or loss	2,026,168	—	818,064	968,541	3,812,773
Reversal of previous provisions	—	—	—	—	—
Unwinding of discount	—	—	444,853	—	444,853
Amounts used during the year	(1,311,118)	(281,476)	—	—	(1,592,594)
Carrying amount at end of year	**3,575,444**	**—**	**21,262,717**	**1,712,422**	**26,550,583**

18. OTHER FINANCIAL LIABILITIES

	2017 $	2016 $
Current		
Lease incentive liabilities	38,600	—
	38,600	**—**
Non-Current		
Lease incentive liabilities	122,233	—
Liabilities associated with forward gas sales agreements containing a cash settlement option (Refer Note 3)	21,792,304	11,765,271
	21,914,537	**11,765,271**

19. CONTRIBUTED EQUITY

(a) Share capital

	2017 $	2016 $
433,197,647 (2016: 433,197,647) fully paid ordinary shares	172,301,532	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

	2017 No. of shares	2016 No. of shares	2017 $	2016 $
Balance at start of year	433,197,647	368,718,957	172,301,532	160,785,182
Placement of shares to institutional investors on 17 November 2015 at 19 cents per share	—	55,307,843	—	10,508,490
Shares issued pursuant to the Security Purchase Plan on 11 December 2015 at 19 cents per share	—	9,170,847	—	1,742,500
Capital raising costs	—	—	—	(734,640)
	433,197,647	**433,197,647**	**172,301,532**	**172,301,532**

19. CONTRIBUTED EQUITY (CONTINUED)

(c) Options granted during the year

The following options over unissued ordinary shares were granted by the Company during the year:

DATE OF ISSUE	CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
07 March 2017	Unlisted employee options	05 Nov 2017	45 cents	430,827

(d) Options exercised during the year

No options were exercised during the year.

(e) Options lapsed or cancelled 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	20 Jul 2016	$0.550	669,334
Unlisted employee options	19 Aug 2016	$0.575	400,000
Unlisted employee options	30 Aug 2016	$0.575	600,000
Unlisted employee options	15 Nov 2016	$0.475	2,318,668
Unlisted employee options	30 Nov 2016	$0.475	400,000
Unlisted employee options	19 Dec 2016	$0.475	900,000

The following options over unissued ordinary shares were cancelled during the year:

CLASS	DATE CANCELLED	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted employee options	19 Dec 2016	$0.475	900,000
Unlisted employee options	24 Apr 2017	$0.650	366,600
Unlisted employee options	24 Apr 2017	$0.475	1,899,350
Unlisted employee options	24 Apr 2017	$0.450	2,325,967
Unlisted employee options	24 Apr 2017	$0.410	234,000
Unlisted employee options	24 Apr 2017	$0.400	417,425

(f) 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 consulting options	15 Nov 2017	$0.450	24,900,773
Unlisted director options	15 Nov 2017	$0.450	1,466,667
Unlisted employee options	15 Nov 2017	$0.400	365,100
Unlisted employee options	15 Nov 2017	$0.450	1,800,595
Unlisted employee options	15 Nov 2017	$0.650	27,300
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)

(g) 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	2,099,685
Employee LTIP rights	05 Jan 2021	1 Jul 2014	191,031
Employee LTIP rights	08 Dec 2022	1 Jul 2014	398,571
Employee LTIP rights	05 Jan 2021	1 Jul 2015	5,789,299
Employee LTIP rights	09 Feb 2021	1 Jul 2015	1,913,873
Employee LTIP rights	08 Dec 2022	1 Jul 2015	139,718
Employee LTIP rights	08 Dec 2022	1 Jul 2016	13,509,417
Employee LTIP rights	09 Feb 2022	1 Jul 2016	31,655

No Rights were converted to shares during the year. The Rights do not entitle the holders to participate in any share issue of the Company or any other entity.

(h) 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

	2017 $	2016 $
Share options reserve	**21,841,455**	**19,590,431**
Movements:		
Balance at start of year	19,590,431	16,695,379
Share based payment costs (a)	2,251,024	2,235,544
Options issued for financing (b)	–	659,508
Balance at end of year	**21,841,455**	**19,590,431**

(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.

(b) In 2016 30 million options with an exercise price of $0.20 were issued to Macquarie bank in relation to the expanded debt facility. These new options replaced the 15 million options previously issued to Macquarie (with an exercise price of $0.50) and were valued using a Black Scholes option pricing model.

21. ACCUMULATED LOSSES

	2017 $	2016 $
Movements in accumulated losses were as follows:		
Balance at the start of year	(175,374,353)	(154,334,061)
Net loss for the year	(24,726,481)	(21,040,292)
Balance at end of year	**(200,100,834)**	**(175,374,353)**

22. LOSSES PER SHARE

(a)	**Basic loss per share (cents)**	**(5.71)**	**(5.16)**
(b)	**Diluted loss per share (cents)**	**(5.71)**	**(5.16)**
(c)	**Loss used in loss per share calculation**		
	Loss attributed to ordinary equity holders of the Company	**(24,726,481)**	**(21,040,292)**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic and diluted earnings per share	**516,313,022**	**408 108 471**

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. Refer to Note 19(f) for details of options on issue.

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.

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 2017 $	EXPLORATION ASSETS 2017 $	CORPORATE ITEMS 2017 $	CONSOLIDATION 2017 $
Revenue (a)	24,794,145	—	—	24,794,145
Cost of sales (b)	(15,701,690)	—	—	(15,701,690)
Gross profit	9,092,455	—	—	9,092,455
Other income (e)	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 (c)	—	—	—	—
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 (d)	(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) Revenue for 2017 includes a full year contribution from Mereenie (10 months for 2016 year). Revenue for the prior corresponding period (2016) included $1,220,000 received as stand-by fees under a short term arrangement with Power & Water Corporation.

(b) Cost of sales for 2017 includes a full year contribution from Mereenie (10 months for 2016 year).

(c) Other operating costs for 2016 comprised a one-off amount of $1,725,000 in respect of restructuring future contingent production bonus payments from the Mereenie field, effectively eliminating the future contingent liability (refer Note 29 (a) (iii))

(d) 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. A financial settlement would be paid out of the proceeds of gas sold under the new gas sales agreements.

(e) 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.

23. SEGMENT REPORTING (CONTINUED)

	PRODUCING ASSETS 2016 $	EXPLORATION ASSETS 2016 $	CORPORATE ITEMS 2016 $	CONSOLIDATION 2016 $
Revenue	23,862,569	—	—	23,862,569
Cost of sales	(14,060,704)	—	—	(14,060,704)
Gross profit	9,801,865	—	—	9,801,865
Other income	75,216	3,206	181,517	259,939
Share based employee benefits	—	—	(2,235,544)	(2,235,544)
General and administrative expenses	—	(18,088)	(487,586)	(505,674)
Employee benefits and associated costs	—	—	(4,478,454)	(4,478,454)
Other operating expenses (c)	—	—	(1,725,000)	(1,725,000)
EBITDAX	**9,877,081**	**(14,882)**	**(8,745,067)**	**1,117,132**
Depreciation and amortisation	(8,152,097)	(20,121)	(231,935)	(8,404,153)
Exploration expenditure	(1,614,318)	(2,411,309)	—	(4,025,627)
Finance costs	(7,754,625)	(5,756)	(530,218)	(8,290,599)
Impairment expense	(37,045)	(1,400,000)	—	(1,437,045)
Loss before income tax	**(7,681,004)**	**(3,852,068)**	**(9,507,220)**	**(21,040,292)**
Taxes	—	—	—	—
Loss for the year	**(7,681,004)**	**(3,852,068)**	**(9,507,220)**	**(21,040,292)**
Segment assets	**129,604,324**	**11,371,307**	**10,399,215**	**151,374,846**
Segment liabilities	**(118,735,778)**	**(3,625,668)**	**(12,495,790)**	**(134,857,236)**
Capital expenditure				
Mereenie asset acquisition	60,759,382	—	—	60,759,382
Property, plant and equipment	2,728,791	—	229,274	2,958,065
Total capital expenditure	**63,488,173**	—	**229,274**	**63,717,447**

	2017 $	2016 $
Revenue from external customers by geographical location of production		
Australia	24,794,145	23,862,569
Non-current assets by geographical location		
Australia	122,205,500	128,879,308

Major Customers

Revenue from one customer represents $7,600,694 or 31% of the Group's total oil and gas revenues (2016: $8,113,631 or 36 % of the Group's total oil and gas revenues). Revenue from a second customer represents $6,398,720 or 26% of the Group's total oil and gas revenues (2016: $6,985,762 or 32% of the Group's oil and gas revenues). Revenue from a third customer represents $5,632,967 or 23% of the Group's total oil and gas revenues (2016: $5,000,264 or 22% of the Group's oil and gas revenues).

No other customers had revenue exceeding 10% of the Group's total oil and gas revenue for the 2017 year.

24. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2017 $	2016 $
Statement of financial position		
Current assets	5,999,204	11,377,033
Non-current assets	9,131,712	8,864,537
Total assets	15,130,916	20,241,570
Current liabilities	(7,656,045)	(7,013,781)
Total liabilities	(8,503,576)	(7,096,181)
Net assets	**6,627,340**	**13,145,389**
Shareholders' equity		
Issued capital	172,301,532	172,301,532
Reserves	21,841,455	19,590,431
Accumulated losses	(187,515,647)	(178,746,574)
Total equity	**6,627,340**	**13,145,389**
Loss for the year	**(8,769,073)**	**(15,895,155)**
Total comprehensive loss	**(8,769,073)**	**(15,895,155)**

(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 Palm Valley and Dingo assets (such as Surprise) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

(c) Contingent assets and liabilities of the Parent Entity

Under a Sale and Purchase Deed with Macquarie Bank Limited dated 26 May 2016, Central Petroleum Limited acquired a 50% beneficial interest in the rights to any bonus as described in Note 29(a)(iii).

(d) Commitments of the Parent Entity

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

25. RELATED PARTY TRANSACTION

(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 **2017** %	2016 %
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 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

(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

	2017 $	2016 $
Short-term employee benefits	2,373,766	2,862,486
Post-employment benefits	142,141	215,877
Termination benefits	—	116,923
Long-term benefits	46,583	38,867
Share based payments	1,798,104	1,902,000
	4,360,594	5,136,153

Detailed remuneration disclosures are provided in the remuneration report on pages 20 to 29.

(b) Equity instrument disclosures relating to key management personnel

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

Details of options provided as remuneration and shares issued on the exercise of such options, together with the terms and conditions of the options, can be found in the remuneration report on pages 20 to 29.

26. KEY MANAGEMENT PERSONNEL (CONTINUED)

(b) Equity instrument disclosures relating to key management personnel (continued)

(ii) Option holdings

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	FORFEITED	HELD AT DATE OF DEPARTURE	BALANCE AT END OF YEAR	VESTED EXERCISABLE	UNVESTED
Non-Executive Directors									
Wrixon Gasteen	2017	666,666	—	—	(666,666)	N/A	—	—	—
	2016	1,000,000	—	—	(333,334)	N/A	666,666	—	666,666
Executive Directors and Other Key Management Personnel									
Richard Cottee[1]	2017	24,900,773	—	—	—	N/A	24,900,773	—	24,900,773
	2016	34,584,407	—	—	(9,683,634)	N/A	24,900,773	—	24,900,773
Michael Herrington	2017	1,950,000	—	—	(1,950,000)	N/A	—	—	—
	2016	2,250,000	—	—	(300,000)	N/A	1,950,000	—	1,950,000
Daniel White	2017	760,000	—	—	(760,000)	N/A	—	—	—
	2016	1,493,334	—	—	(733,334)	N/A	760,000	310,000	450,000
Leon Devaney	2017	504,000	—	—	(504,000)	N/A	—	—	—
	2016	1,064,000	—	—	(560,000)	N/A	504,000	—	504,000
Robbert Willink[2]	2017	N/A	—	—	N/A	N/A	N/A	N/A	N/A
	2016	450,000	—	—	(120,000)	N/A	330,000	—	330,000

[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. Options still on hand at 30 June 2017 (and 30 June 2016) expire 15 November 2017.*

[2] *Mr Willink is not considered Key Management Personnel for the 2017 year*

(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.

26. KEY MANAGEMENT PERSONNEL (CONTINUED)

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	2017	2,104,904	3,202,983	—	N/A	—	5,307,887
	2016	—	2,104,904	—	N/A	—	2,104,904
Michael Herrington	2017	930,000	1,956,237	—	N/A	—	2,886,237
	2016	—	930,000	—	N/A	—	930,000
Daniel White	2017	1,100,000	1,289,666	—	N/A	—	2,389,666
	2016	330,000	770,000	—	N/A	—	1,100,000
Leon Devaney	2017	1,061,571	1,311,533	—	N/A	—	2,373,104
	2016	278,571	783,000	—	N/A	—	1,061,571
Robbert Willink[1]	2017	N/A	—	—	N/A	—	N/A
	2016	262,286	—	—	N/A	—	262,286

[1] Mr Willink is not considered Key Management Personnel for the 2017 year

(iii) 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 OPTIONS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Wrixon Gasteen	2017	136,473	—	—	—	—	N/A	136,473
	2016	97,000	—	39,473	—	—	N/A	136,473
Robert Hubbard	2017	298,947	—	—	—	—	N/A	298,947
	2016	120,000	—	178,947	—	—	N/A	298,947
Peter Moore	2017	—	—	—	—	—	N/A	—
	2016	—	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2017	632,438	—	—	—	(60,609)[1]	N/A	571,829
	2016	436,383	—	196,055	—	—	N/A	632,438
Michael Herrington[2]	2017	250,000	—	—	—	—	N/A	250,000
	2016	250,000	—	—	—	—	N/A	250,000
Daniel White	2017	288,000	—	—	—	—	N/A	288,000
	2016	288,000	—	—	—	—	N/A	288,000
Leon Devaney	2017	210,000	—	—	—	—	N/A	210,000
	2016	210,000	—	—	—	—	N/A	210,000

[1] Shares held by members of Mr Cottee's family and no longer considered under Mr Cottee's control have been removed from this table.

26. KEY MANAGEMENT PERSONNEL (CONTINUED)

(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

	2017 $	2016 $
Loss after income tax	(24,726,481)	(21,040,292)
Adjustments for:		
Depreciation and amortisation	7,780,576	8,404,153
Loss on disposal of assets	47,665	1,445
Profit on disposal of exploration permits	(280,000)	—
Share-based payments	2,251,024	2,235,544
Income tax expense	—	—
Impairment expense	89,013	1,437,045
Restatement of financial liabilities	9,493,259	—
Financing costs and interest (non-cash)	1,019,499	971,582
Changes in assets and liabilities relating to operating activities:		
(Increase) / Decrease in trade and other receivables	(1,208,938)	2,082,054
Decrease in inventories	319,547	47,307
Decrease in other financial assets	17,785	—
Decrease in trade and other payables	(1,893,483)	(1,393,931)
Increase in deferred revenue	4,030,668	3,967,407
Increase in financial liabilities	160,833	—
Increase in provisions	2,665,032	1,794,910
Net Cash Inflow/(Outflow) from Operations	**(234,001)**	(1,492,776)

28. NON CASH INVESTING AND FINANCING ACTIVITIES

There were no non-cash financing or investing activities during the year (2016: Nil).

29. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2017 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 (2016: $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.

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) Mereenie Sales Bonus

Central Petroleum Mereenie Pty Ltd as trustee for The Central Petroleum Mereenie Unit Trust (“CPMUT”) indemnified Santos QNT in respect of 50% of any Bonus Amount payable by Santos QNT to Macquarie Bank Limited (“MBL”).

The Bonus Amount may become payable to MBL if, at any time until 1 July 2031, the 90-Day Average Net Sales exceeds certain threshold levels. At financial year end the 90-Day Average Net Sales from Mereenie did not exceed the threshold levels and therefore no Bonus Amount was payable.

On 26 May 2016, CPMUT entered into a Sale and Purchase Deed with MBL under which CPMUT is entitled to receive 50% of the Bonus Amount payments received by MBL. This in effect offsets the Consolidated Entity’s exposure to 50% of the Bonus Amount indemnity in favour of Santos QNT as described above.

(iv) Litigation

The Company is involved 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. The Company has lodged an appeal from the order of the court denying the Company’s objection to the court’s jurisdiction. The Company has denied any liability.

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 is opposing jurisdiction of the Supreme Court of Queensland.

29. CONTINGENCIES (CONTINUED)

(v) NGP Bonus

Under the Sale and Purchase Deed entered into with Santos in June 2015 for the purchase of an interest in the Mereenie oil and gas assets, the Group may become obligated to pay Santos an NGP Bonus consisting of a $15 million lump sum payment and sole funding a gas field development project ($55 million - $75 million). The NGP Bonus will not become payable unless the Group enters into a Gas Transportation Agreement (“GTA”) with the NGP (Northern Gas Pipeline) project owner within 3-years of execution date (by 3 June 2018). For example, the NGP Bonus would not be triggered by the Group entering into a Gas Sales Agreement to deliver gas to a customer at a point Upstream of the NGP.

The Group considers that the NGP Bonus obligation is unlikely given the Group has control over the trigger event and have therefore ascribed a $Nil value to this contingent liability.

(b) Contingent assets

Under a Sale and Purchase Deed with MBL dated 26 May 2016, Central Petroleum Limited acquired a 50% beneficial interest in the rights to any bonus as described in paragraph (a)(iii) above. The bonus is payable by MBL to Central Petroleum Limited. As discussed above, the value of this contingent asset effectively offsets the Group’s contingent liability associated with the Mereenie Sales Bonus. .

30. COMMITMENTS

(a) Capital commitments

The Consolidated Entity has the following exploration expenditure commitments:

	2017 $	2016 $
The following amounts are due:		
Within one year	4,630,000	10,750,000
Later than one year but not later than three years	25,180,000	4,160,000
Later than three years but not later than five years	2,400,000	12,750,000
	32,210,000	**27,660,000**

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.

(b) 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	465,421	743,676
Later than one year but not later than five years	1,404,222	947,465
	1,869,643	**1,691,141**

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.	$
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	

31. SHARE BASED PAYMENTS (CONTINUED)

EXPIRY DATE	EXERCISE PRICE[7]	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.	$
2016						—	—
31 Oct 2015	$0.550	120,000	—	—	(120,000)	—	—
15 Nov 2015	$0.400	220,000	—	—	(220,000)	—	—
15 Nov 2015	$0.450	9,683,634	—	—	(9,683,634)	—	—
15 Nov 2015	$0.450	4,354,334	—	—	(4,354,334)	—	—
15 Nov 2015	$0.450	1,366,670	—	—	(1,366,670)	—	—
15 Nov 2015	$0.650	207,000	—	—	(207,000)	—	—
12 May 2016	$0.600	40,000	—	—	(40,000)	—	—
20 Jul 2016	$0.550	669,334	—	—	—	669,334	669,334
19 Aug 2016	$0.575	400,000	—	—	—	400,000	400,000
30 Aug 2016	$0.575	600,000	—	—	—	600,000	600,000
15 Nov2016	$0.475	2,318,668	—	—	—	2,318,668	2,318,668
30 Nov 2016	$0.475	400,000	—	—	—	400,000	400,000
15 Nov 2017	$0.450	24,900,773	—	—	—	24,900,773	—
15 Nov 2017	$0.450	2,733,335	—	—	—	2,733,335	—
15 Nov 2017	$0.475	2,799,350	—	—	—	2,799,350	—
15 Nov 2017	$0.450	2,429,068	—	—	—	2,429,068	—
15 Nov 2017	$0.400	782,525	—	—	—	782,525	—
15 Nov 2017	$0.410	234,000	—	—	—	234,000	—
15 Nov 2017	$0.650	393,900	—	—	—	393,900	—
Totals		**54,652,591**	—	—	**(15,991,638)**	**38,660,953**	**4,388,002**
Weighted average exercise price		$0.46	—	—	$0.45	$0.46	$0.51
Weighted average remaining contractual life (years) at the end of the year						1.25	

(b) Employee options granted during the year

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*

No options were granted during the year ending 30 June 2016.

(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	EXPIRED OR FORFEITED	BALANCE AT END OF YEAR
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**
2016							
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	—	—	528,415
14 Oct 2015	30 June 2016	—	6,042,632	$0.147	—	(698,262)	5,344,370
22 Dec 2015	30 June 2015	—	191,031	$0.085	—	—	191,031
17 Jun 2015	30 June 2015	2,811,397	—	$0.074	—	(274,285)	2,537,112
Totals		**2,811,397**	**8,682,014**		—	**(972,547)**	**10,520,864**

(d) Expenses arising from share-based payment transactions

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

	2017	2016
	$	$
Options and rights issued to directors and employees	2,251,024	2,235,544

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.

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

TRADE AND OTHER RECEIVABLES	GROSS 2017 $	GROSS 2016 $	IMPAIRMENT 2017 $	IMPAIRMENT 2016 $
Past due: 0-30 days	4,222,021	3,021,644	—	—
Past due: 31-150 days	—	—	—	—
Past due: 151-365 days	—	—	—	—
	4,222,021	**3,021,644**	—	—

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 2017 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.

(b) Liquidity Risk

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

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)**

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

2016	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	15,115,699	—	—	—	15,115,699
Trade and other receivables	3,021,644	—	—	—	3,021,644
Other financial assets	—	—	2,208,624	—	2,208,624
	18,137,343	**—**	**2,208,624**	**—**	**20,345,967**
Financial Liabilities					
Trade and other payables	(6,896,389)	—	(2,621,694)	—	(9,518,083)
Interest bearing liabilities	(2,249,389)	(1,534,805)	(81,916,860)	—	(85,701,054)
Other financial liabilities	—	—	(1,957,771)	(9,807,500)	(11,765,271)
	(9,145,778)	**(1,534,805)**	**(86,496,325)**	**(9,807,500)**	**(106,984,408)**

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.

(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	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
	%	%	**$**	$	**$**	$	**$**	$	**$**	$
Financial Assets:										
Cash and cash equivalents	1.1	1.5	5,478,140	15,115,699	—	—	—	—	5,478,140	15,115,699
Trade and other receivables	—	—	—	—	—	—	4,222,021	3,021,644	4,222,021	3,021,644
Other financial assets	1.1	1.2	—	—	1,233,410	920,982	1,268,537	1,287,642	2,501,947	2,208,624
			5,478,140	**15,115,699**	**1,233,410**	**920,982**	**5,490,558**	**4,309,286**	**12,202,108**	**20,345,967**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(3,239,168)	(6,896,389)	(3,239,168)	(6,896,389)
Interest bearing liabilities	7.4	7.7	(81,916,861)	(85,431,135)	(252,893)	(269,919)	—	—	(82,169,754)	(85,701,054)
Other financial liabilities	—	—	—	—	—	—	(21,953,137)	(11,765,271)	(21,953,137)	(11,765,271)
			(81,916,861)	**(85,431,135)**	**(252,893)**	**(269,919)**	**(25,192,305)**	**(18,661,660)**	**(107,362,059)**	**(104,362,714)**
Net Financial Assets / (Liabilities)			**(76,438,721)**	**(70,315,436)**	**980,517**	**651,063**	**(19,701,747)**	**(14,352,374)**	**(95,159,951)**	**(84,016,747)**

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

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 2016.

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2017				
Cash and cash equivalents	6,210	(6,210)	—	—
Interest bearing liabilities	(603,045)	603,045	—	—
2016				
Cash and cash equivalents	10,371	(10,371)	—	—
Interest bearing liabilities	(656,002)	656,002	—	—

(d) Commodity Risk

The Consolidated Entity is exposed to commodity price fluctuations in respect of crude oil sales. The Consolidated Entity does not hedge crude oil sales. Gas sales are made under long term contracts and as such do not contain any commodity risk.

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 following 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's) 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
2017				
Other financial liabilities	(1,730,218)	952,587	—	—

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
2017				
Other financial liabilities	(549,107)	106,703	—	—

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(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.

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 small 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.

(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	**2017** %	2016 %
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[3])	Oil & gas exploration	60.00	60.00
EPA 111 (Santos)	Oil & gas exploration – application	50.00	100.00
EPA 124 (Santos)	Oil & gas exploration – application	50.00	100.00
ATP 909 (previously with Total[2])	Oil & gas exploration	100.00	90.00
ATP 911 (previously with Total[2])	Oil & gas exploration	100.00	90.00
ATP 912 (previously with Total[2])	Oil & gas exploration	100.00	90.00

[1] *Macquarie Mereenie acquired 50% interest form Santos effective 1 January 2017*
[2] *Total = TOTAL GLNG Australia*
[3] *Santos = Santos Group companies*

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.

33. INTEREST IN JOINT ARRANGEMENTS (CONTINUED)

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:

	2017 $	2016 $
Current assets		
Cash and cash equivalents	396,972	676,283
Trade and other receivables	3,139,181	3,030,340
Inventory	1,357,192	1,667,137
Total current assets	4,893,345	5,373,760
Non-current assets		
Property, plant and equipment	52,143,932	57,251,808
Other financial assets	175,000	182,200
Total non-current assets	52,318,932	57,434,008
Current liabilities		
Trade and other payables	605,789	4,251,428
Accruals	381,094	513,980
Deferred revenue	730,878	730,878
Provision for production over-lift	—	743,881
Total current liabilities	1,717,761	6,240,167
Non-current liabilities		
Deferred revenue	439,497	439,497
Joint Venture under contributions	—	2,069,220
Provision for production over-lift	1,712,422	—
Restoration provision	11,658,569	12,166,972
Total non-current liabilities	13,810,488	14,675,689
Net assets / (liabilities)	**41,684,028**	**41,891,912**
Joint arrangement contribution to loss before tax		
Revenue	15,263,637	17,255,241
Other income	2,017,203	—
Expenses	(18,678,419)	(20,817,628)
Profit / (Loss) before income tax	**(1,397,579)**	**(3,562,387)**

34. EVENTS OCCURRING AFTER THE REPORTING PERIOD

On 10 August 2017 the Company announced a $27 million equity raising to support the gas acceleration programme. The equity raising comprised a placement to institutional and sophisticated investors of $9.2 million and a fully underwritten 5 for 12 non-renounceable entitlement offer to raise approximately $18.0 million. The equity raising has been successfully concluded resulting in net proceeds of approximately $25.4 million after costs.

No matter or circumstance has arisen subsequent to 30 June 2017 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 33 to 78 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 2017 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 2017.

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

Richard Cottee
Managing Director
Brisbane

25 September 2017

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 2017 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 2017
- the consolidated statement of profit or loss and other comprehensive income for the year then ended
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows 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.

PricewaterhouseCoopers, ABN 52 780 433 757

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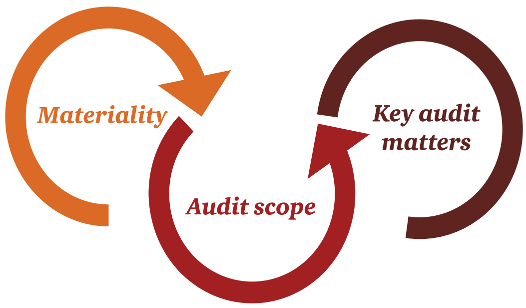
Our audit approach

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 Group's accounting processes and controls and the industry in which it operates.



Materiality

- For the purpose of our audit we used overall group materiality of $1.4 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 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.
- Where necessary, we involved specialists to assist us with certain aspects of our audit.

Key audit matters

We communicated the following key audit matters to the Audit and Risk Committee:

- Basis of preparation of the financial report
- Carrying value of goodwill and producing assets
- Accounting for asset retirement obligations
- 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.

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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. We also considered the equity raise that has occurred as a post balance sheet event to provide additional funding to the Group to develop further gas reserves. 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.
Carrying value of goodwill and producing assets *Refer to notes 9 and 13 of the financial report* The Group produces oil and gas at the Mereenie, Palm Valley and Dingo fields which have been either acquired or developed by the Group. As such there is a material amount of non-current assets, including goodwill. The balances at 30 June 2017 recognised are: – Goodwill - \$3.9m – Property, Plant and Equipment - \$106.8m In line with Australian Accounting Standards, which require companies to test goodwill acquired in a business combination for impairment annually, the Group have performed impairment tests as at 30 June 2017, through preparation of a discounted cashflow model assessing recoverable amount (the impairment model), and have also given consideration to a recent takeover offer and an associated valuation performed by an external valuer. The Group concluded that there was no impairment of the goodwill and producing assets cash generating unit (the CGU assets). We considered this to be a key audit matter given the combined materiality of the balances, the early stages in the development lifecycle of these assets, and the judgmental nature of cash flow forecasts in the impairment model.	In assessing the appropriateness of the Group's conclusion we: • read the Group's assessment of any indicators of impairment and did not identify any further indicators that had not been considered by the Group; • tested the carrying value of the assets and liabilities included in the cash generating unit; • assessed if the recoverable amount calculated by the Group's value in use impairment model exceeded the carrying value of the CGU assets, and no impairment was identified; • compared the carrying value of the CGU assets to two indicators of fair value less cost to sell, being the recent takeover offer by Macquarie Bank Limited and the associated valuation performed by an external valuer, and assessed the appropriateness of using these indicators to assess the recoverable amount; and • evaluated the adequacy of the disclosures made in note 13 to the annual report in light of the requirements of Australian Accounting Standards.

Key audit matter	How our audit addressed the key audit matter
Accounting for retirement obligations *Refer to note 17 of the financial report* Oil and gas companies typically have legal, environmental or constructive obligations to rehabilitate sites, either during or at the end of their operations. The Group have recorded an obligation of $21.3m for this rehabilitation obligation at 30 June 2017. We considered this a key audit matter given that the estimation of rehabilitation provisions involves significant judgment by the Group on the required rehabilitation activities, cost of rehabilitation activities, timing of rehabilitation, inflation and discount factors, amongst other matters. Further, the carrying amount of the obligation is material for the Group.	We held discussions with management to develop an understanding of the methodology and calculation of the rehabilitation provision. We performed tests over the mathematical accuracy of the rehabilitation provision calculations on the various producing fields and exploration tenements. Our audit procedures included assessing the appropriateness of the key assumptions underlying the rehabilitation provision calculation through: • developing an understanding of the extent of field development and production activity through enquiries with operations management and consideration of site restoration plans prepared by environmental experts (the experts); • assessment of the provision calculations to check that they incorporate the restoration activities required as advised by the experts and that the experts' estimated costs of conducting those activities are included in the calculation; • assessment of the competence and objectivity of the experts; • corroborating a sample of estimates in the rehabilitation provision calculations to third party support or internal Group engineer estimates; • checking the decommissioning date in the rehabilitation provision calculation was consistent with evidence supporting the expiry of the resources; and • comparing the discount rate used in the rehabilitation provision calculation with available market information.
Accounting for a gas forward sale agreement with a financial settlement clause *(balance of $21.8m)* *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 and 30 June 2017. 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 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.	We performed the following procedures, amongst others: • held discussions with management and reviewed 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 to 30 June 2017, noting that new agreements had been entered into, 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 • Evaluated the adequacy of the disclosures made in notes 3(a), 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 Chairman's Letter, Managing Director's Letter, Directors' Report, Corporate Directory, Corporate Governance Statement, ASX Additional Information and Interests in Petroleum Permits and Pipeline Licences included in the Group's annual report for the year ended 30 June 2017 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 20 to 29 of the directors' report for the year ended 30 June 2017.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2017 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

Michael Shewan

Partner

25 September 2017

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 18 SEPTEMBER 2017

Top holders

The 20 largest registered holders of the quoted securities as at 18 September 2017 were:

	NAME	NO. OF SHARES	%
1.	Citicorp Nominees Pty Limited	33,067,225	4.68
2.	UBS Nominees Pty Ltd	31,669,736	4.49
3.	Merrill Lynch (Australia) Nominees Pty Limited	25,351,215	3.59
4.	HSBC Custody Nominees Australia Limited – A/C 2	17,924,999	2.54
5.	Bond Street Custodians Ltd <Macquarie Smaller Co's A/C>	17,202,818	2.44
6.	Mr Christopher Ian Wallin + Ms Fiona Kay McLoughlin + Mrs Sylvia Fay Bhatia <Chris Wallin Super Fund A/C>	15,571,648	2.21
7.	Rocket Science Pty Ltd <The Trojan Capital Fund A/C>	15,300,000	2.17
8.	J P Morgan Nominees Australia Limited	14,313,410	2.03
9.	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	2.01
10.	Telunapa Pty LTd <Telunapa Capital A/C>	12,041,667	1.71
11.	Jetosea Pty Ltd	10,589,398	1.50
12.	National Nominees Limited	9,923,469	1.40
13.	Fanchel Pty Ltd	9,316,667	1.32
14.	Kensington Capital Partners Pty Ltd	8,600,000	1.22
15.	Buttonwood Nominees Pty Ltd	8,417,040	1.19
16.	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	7,400,000	1.05
17.	National Nominees Limited <DB A/C>	7,367,697	1.04
18.	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	6,700,000	0.95
19.	Bond Street Custodians Limited <Macquarie Aust Plus A/C>	6,573,149	0.93
20.	Bond Street Custodians Limited <Macquarie Pure Alpha Fund>	6,261,107	0.89
		277,757,912	39.36

DISTRIBUTION SCHEDULE

The distribution schedule of the ordinary fully paid shares as at 18 September 2017 was:

RANGE	HOLDERS	UNITS	%
1 - 1,000	815	388,809	0.06
1,001 -5,000	2,245	6,174,754	0.88
5,001 - 10,000	1,191	9,274,758	1.31
10,001 - 100,000	2,885	106,658,175	15.11
100,001 - Over	847	583,201,151	82.64
Total	7,983	705,697,647	100.00

GEOGRAPHIC BREAKDOWN

The geographic distribution schedule of the ordinary fully paid shares as at 18 September 2017 was:

LOCATION	HOLDERS	UNITS	%
Australia	7,751	691,895,904	98.04
Overseas	232	13,801,743	1.96
Total	7,983	705,697,647	100.00

ASX ADDITIONAL INFORMATION (Continued)

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 18 September 2017 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

HOLDER	UNITS
Macqaurie Group Limited	55,872,974
Troy Harry	38,000,000

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 5,000 shares as at 18 September 2017):

HOLDERS	UNITS
2,910	5,813,563

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[7]	Pedirka Basin NT	Central	100	0		
EP 97[2]	Pedirka Basin NT	Central	100	0		
EP 105[1]	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106[4]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 107[5]	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)[6]	Amadeus Basin NT	Central	50	50	Macquarie	50
OL 5 (Mereenie)[6]	Amadeus Basin NT	Central	50	50	Macquarie	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[8]	Georgina Basin QLD	Central	100	100		
ATP 911[8]	Georgina Basin QLD	Central	100	100		
ATP 912[8]	Georgina Basin QLD	Central	100	100		

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[3]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124[3]	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	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 (Continued)

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 respective farmout agreement. The participating interests as stated assume such obligations have been met, otherwise may be subject to change.*

[2] *On 20 June 2016, Central submitted an application to the NT Department of Mines and Energy for consent to surrender Exploration Permit 97. The application is currently under review.*

[3] *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..*

[4] *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.*

[5] *On 23 September 2016 Central submitted an application to the NT Department of Primary Industry and Resources for consent to surrender Exploration Permit 107. The application is currently under review.*

[6] *As per Central’s announcement dated 20 December 2016, Santos sold its 50% interest in the Mereenie Oil & Gas Field (OL 4 and OL 5) and the Alice Springs Pipeline (PL 2) to Macquarie Mereenie Pty Ltd (a subsidiary of Macquarie Group Limited) with effect on and from 1 January 2017.*

[7] *On 25 January 2017 Central submitted an application to the NT Department of Primary Industry and Resources for consent to surrender Exploration Permit 93. The application is under review.*

[8] *As per Central’s announcement dated 27 February 2017, Total GLNG Australia elected not to proceed with the Stage 2 Farmin into Central’s Queensland Permits. As a result, Central will retain a 100% interest in the acreage.*