2016 Annual Report

Central Petroleum Limited

Developing the Northern Territory

Serving Australia's Gas Needs

Central Petroleum

Central Petroleum Limited | ABN 72 083 254 308

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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

REGISTERED OFFICE

Level 7, 369 Ann Street, Brisbane, Queensland 4000
Telephone: +61 7 3181 3800
Facsimile: +61 7 3181 3855
www.centralpetroleum.com.au

AUDITORS

PricewaterhouseCoopers
480 Queen Street, Brisbane, Queensland 4000

BANKERS

ANZ Banking Group
111 Eagle Street, Brisbane, Queensland 4000

SHARE REGISTER

Computershare Investor Services Pty Limited
117 Victoria Street, West End, Queensland 4101
Telephone: +61 7 3237 2110
Facsimile: +61 3 9473 2085
www.computershare.com.au

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

This year's Annual Report highlights the continued progression of Central Petroleum Limited ("Central" or "Company") from developer to operator to being positioned to take advantage of the tightening east coast gas market and the further economic development of the Northern Territory. In addition, it is pleasing to note the positive underlying EBITDAX achieved this financial year, the first time in the company's history.

Central identified the oncoming challenges of the east coast gas market when, three years ago, Richard and his team pivoted our strategy from oil exploration to a gas focused business. However, even we have been surprised by the economic consequences and escalating prices being experienced on the east coast this winter. The future of many significant industrial enterprises and their employees depend on swift resolution to this dilemma. However, despite the announcement of the Northern Gas Pipeline ("NGP"), challenges remain to be overcome before Central can participate in the east coast gas market, not least of which is a regime which produces transportation costs that reward pipeline owners with greater returns than enterprises that bear the far greater risk of either exploring for and developing gas reserves or for our future customers manufacturing products to compete in global markets. The speed with which the Federal and State Governments have responded to the ACCC report which highlighted this economic imbalance is testimony to the magnitude of the issue.

During the year we consummated the transfer of Mereenie operations to Central management and brought our Dingo field into operation. The faith that our valued Mereenie Joint Venture Partner, Santos, placed in our Company when transferring operational management to Central has been rewarded. In our first year of operations Mereenie has maintained an excellent environmental and safety record, increased its local and indigenous employment and lowered its operating costs significantly. Dingo is now a valued supplier to Power and Water Corporation ("PWC") capable of increasing supply as PWC expand its activities.

Central has and will continue to take an active part in debating the issues key to the economic and social development of the Northern Territory. We appreciate that our licence to operate comes from the communities of which we are part. In return, we must take actions that support our words and clearly demonstrate that our businesses are good for the community, the economy and the environment. Over 50% of our employees now live locally in the Northern Territory, more than 25% from indigenous heritage. Central generates royalties and has a Northern Territory first procurement approach; we are and want to be a growing part of the Northern Territory economy. Finally, our operations are well established with decades of sound environmental performance. We appreciate the right of our communities to demand the highest levels of environmental management, often through their elected representatives, and Central willingly participates in this debate. However, for the long term benefit of the Northern Territory the debate and policy must be evidence not opinion based.

Central's achievements are a team effort and I would like to thank my colleagues on the Board, Richard Cottee and his accomplished senior executives and rest of the team at Central. In particular, we all appreciated the guidance and knowledge that Tom Wilson provided in his time on the board. Tom's knowledge of the Amadeus Basin has been invaluable as we continued to grow our operations.

Finally, my last thank you is to you, our shareholders for your ongoing support and encouragement. Your Board appreciates that it has been a difficult year for the Central share price, however, we believe our strategy remains true and tenacity will be rewarded. In the meantime we continue to reduce costs wherever possible and improve our efficiency and effectiveness so we can pursue opportunities as they arise.

Best wishes

Robert Hubbard
Chairman
Brisbane

21 September 2016

MANAGING DIRECTOR'S LETTER

Dear Fellow Shareholders

Last year may mark a huge turning point in the fortunes of your Company. During the year Central:

- assumed operatorship of the Mereenie oil and gas field and settled on the final payment for Mereenie in June 2016
- completed the free-carry work at Mereenie, resulting in a 1P reserves increase of 88 PJ (240%) and a 2P reserves increase of 27 PJ (22%) (gross joint venture basis)
- physically delivered first gas from the Dingo field to the Owen Springs Power Station
- saw the Northern Gas Pipeline ("NGP") announced with the steel pipe ordered in April 2016
- increased local employment to over 50% of our NT operation's workforce
- saw the ACCC Inquiry validate the foundations of our strategic shift commenced over three years ago to concentrate on domestic gas production. The ACCC, in its report, stated that there was an urgent need for "new gas supplies and new gas suppliers"
- maintain our safety record below industry averages.

The NGP was awarded without requiring the Central-operated gas fields to contractually commit to transporting its gas through the NGP. Despite this, the NGP has been sized to allow the transportation of our known gas reserves through it without compression.

The ACCC Inquiry into the East Coast Gas Market, published in April this year, made two important recommendations, which, if implemented, would materially enhance your Company's ability to supply the east coast gas market with new supplies, making Central a new supplier to that market. The first of these recommendations was to change the regulation coverage test from covering only vertically integrated pipeline owners to major pipelines generally. The second was that the present "regulatory regime is not fit for purpose for the gas pipeline sector". The result of it not being fit for purpose was widespread evidence of "monopolistic" pricing. The ACCC has stated in their report that one pipeline operator "indicated that it is earning 70% more revenue than it would if it was subject to full regulation".

The joint communique from the Council of Australian Governments ("COAG") stated that the "Ministers are concerned that, based on the ACCC findings, the current test does not appear to be working, and a new test may be needed to put downward pressure on transport prices". Further, in the media release of the Hon. Josh Frydenberg MP, the Federal Minister for the Environment and Energy stated, "To fast track implementation of the recommendations from these reports, Council will form a new Gas Market Reform Group headed by Dr Michael Vertigan. These are the most significant reforms to the domestic gas market in two decades".

Central is hoping that these reforms are known well before the commissioning of the NGP, thus enabling it to economically increase further supplies into the east coast gas market and have the signal necessary to invest "risk" capital into increasing our reserves.

The Northern Territory Government recently announced a fraccing moratorium on unconventional shale-gas exploration pending the outcome of a fraccing inquiry. As our fields are conventional fields, two of them in production since the 1980's, this moratorium will not affect our ability to supply the gas necessary to generate 40% of Alice Springs' electricity, nor the ability to continue our local and indigenous employment initiative, nor prevent filling the NGP by the time of its commissioning.

I thank shareholders, our Company employees (including senior management) and the Board for their continued support as we chart a course through very interesting times to the promised wealth and job creating future that beckons.

Richard Cottee
Managing Director
Brisbane

21 September 2016

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2016

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 2016.

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)
Andrew P Whittle (resigned 2 November 2015)

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 (2015: $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:

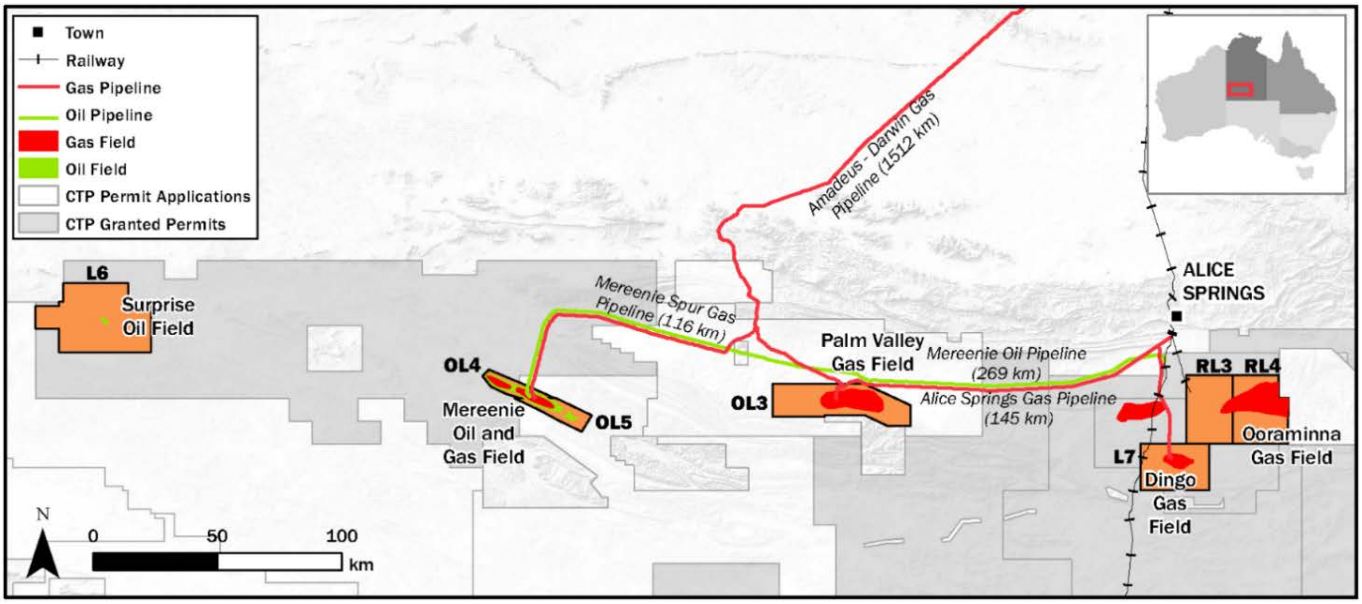
- An annual HSE performance of 1.07 Total Recordable Incidents per Million Man Hours and a Lost Time Incident rate of zero. Significantly below the industry standard.
- Completion of the 50% acquisition of the Mereenie oil and gas field and operatorship assumed effective 1 September 2015, which, together with the Palm Valley and Dingo fields, brings to three the total producing fields in the Amadeus Basin providing security of supply and operational flexibility.
- Dingo gas field commenced deliveries of gas into the Owens Springs Power Station.
- Development of the NGP (Northern Gas Pipeline, formerly known as NEGI, the North East Gas Interconnector) progressed with the Northern Territory Government's announcement that Jemena Northern Gas Pipeline Pty Ltd had been selected to construct and operate the pipeline.
- Capital Raising to support NGP reserves certification embarked upon with a Share Placement raising $10.5 million gross in November 2015 and a Share Purchase Plan raising an additional $1.7 million gross in December 2015.
- ACCC report "Inquiry into the East Coast Gas Market" corroborates the Company's gas strategy.
- Mereenie Field Development program was optimised to maximise reserve upgrades and reduce costs. The savings realised through these efficiency gains will be used to further develop the Company's knowledge of the Stairway and P4 formations. The Reserve Upgrade Program comprises three stages:
    - Stage 1 – Consisted of reviewing all existing data from Mereenie including nearly 60 wells already drilled and selected wire-line pressure and flow testing at Mereenie and the building and history matching of a static and dynamic model of the gas reservoir at Mereenie. This was completed at a cost of $4 million.
    - Stage 2 – Subject to joint venture approval consists of refining and optimising of Stage 1, including possible production testing. This should increase further the reserves available for contracting. In addition, production results at Dingo will be incorporated.
    - Stage 3 – Subject to joint venture approval will consist of appraisal drilling and production testing on the Stairway Formation generally with a target of doubling the Stage 2 reserves at Mereenie. Successful completion of the Stage 3 reserves plus reserve upgrades at Palm Valley and Dingo would result in future sales to Central (including deliveries under existing contracts) of around 250 PJ.

- Stage 1 of Reserve Upgrade Programme completed and results certified by Netherland, Sewell and Associates Inc. resulting in 240% increase in Mereenie's Proved reserves to 62 PJ and a 22% increase in Proved and Probable reserves to 75 PJ (Central equity accounted). In addition, a 50% increase in 2C resources.
- The recommendations outlined in the ACCC Inquiry into the East Coast Gas Market were taken to the Council of Australian Governments ("COAG") by the Federal Minister for Environment and Energy on 19 August 2016 following the electricity crisis in South Australia and Tasmania.
- A Gas Sales and Prepayment Agreement was signed with Macquarie Bank Limited ("MBL") for 5.2 PJs of prepaid gas supplied over three years with up to 3.5 PJs of additional gas sales possible over two subsequent years. Immediate payment under this agreement for the 5.2 PJs was received by Central.
- Under a Sale and Purchase Deed with MBL, dated 26 May 2016, Central removed its exposure to the bonus as described in paragraph Note 31(a)(iii). 50% of the bonus is payable by MBL to Central Petroleum Limited. This effectively offsets the Consolidated Entity's obligations to indemnify Santos for the 50% of any Bonus payable.
- The final $10 million acquisition payment was made to Santos for Central's 50% interest in the Mereenie oil and gas field.
- Central reached a majority of field personnel being locally employed in the second half of the year delivering on its policies:
  - Family values for working families
  - Northern Territory for Northern Territorians
  - Traditional values for Traditional Owners
  - Supporting local businesses
  - Payment of royalties to the Northern Territory Government.
- Annual statutory plant inspections at Mereenie and Dingo were carried out with Palm Valley providing gas to customers while plants were shut-down.
- 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%.
- Underlying EBITDAX positive for the first time in the Company's history, despite low oil prices and only 10-months contribution from Mereenie.

Operating Result

The Consolidated Entity had an operating loss after income tax for the year ended 30 June 2016 of $21.04 million (2015: loss of $27.73 million). On an underlying EBITDAX[1] basis, the Consolidated Entity achieved a full year net income of $2.86 million (2015: loss of $8.84 million). In addition, non-cash share based payment expense included in the above results amounted to $2.24 million (2015: $2.25 million).

1 *EBITAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.*



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

Key results for the reporting period were:

- **Sales Volumes** of 98,635 barrels of crude oil (2015: 53,925 barrels) and 3,230 TJ of gas (2015: 1,194 TJ). The increase reflects the acquisition of a 50% interest in the Mereenie oil and gas field from 1 September 2015 and the commencement of production from the Dingo gas field in late 2015.
- **Sales Revenue** of $22.64 million, up 120% on the previous financial year, reflecting increased production as a result of the Mereenie asset acquisition in September 2015 and the commencement of production from the Dingo gas field. An average oil price of A$58 was realised during the year, down from A$93 in the prior corresponding period. Realised gas prices were also higher than the prior year as a result of the Mereenie acquisition and Dingo production.
- **Underlying loss**[1] of $17.87 million, down from an underlying loss of $22.96 million in the prior year. The statutory loss after tax was $21.04 million, down from a statutory loss of $27.73 million in the previous financial year.
- **Exploration expenditure** of $4.03 million, down from $7.66 million in the previous financial year, reflecting lower drilling activities in the southern Georgina Basin.

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

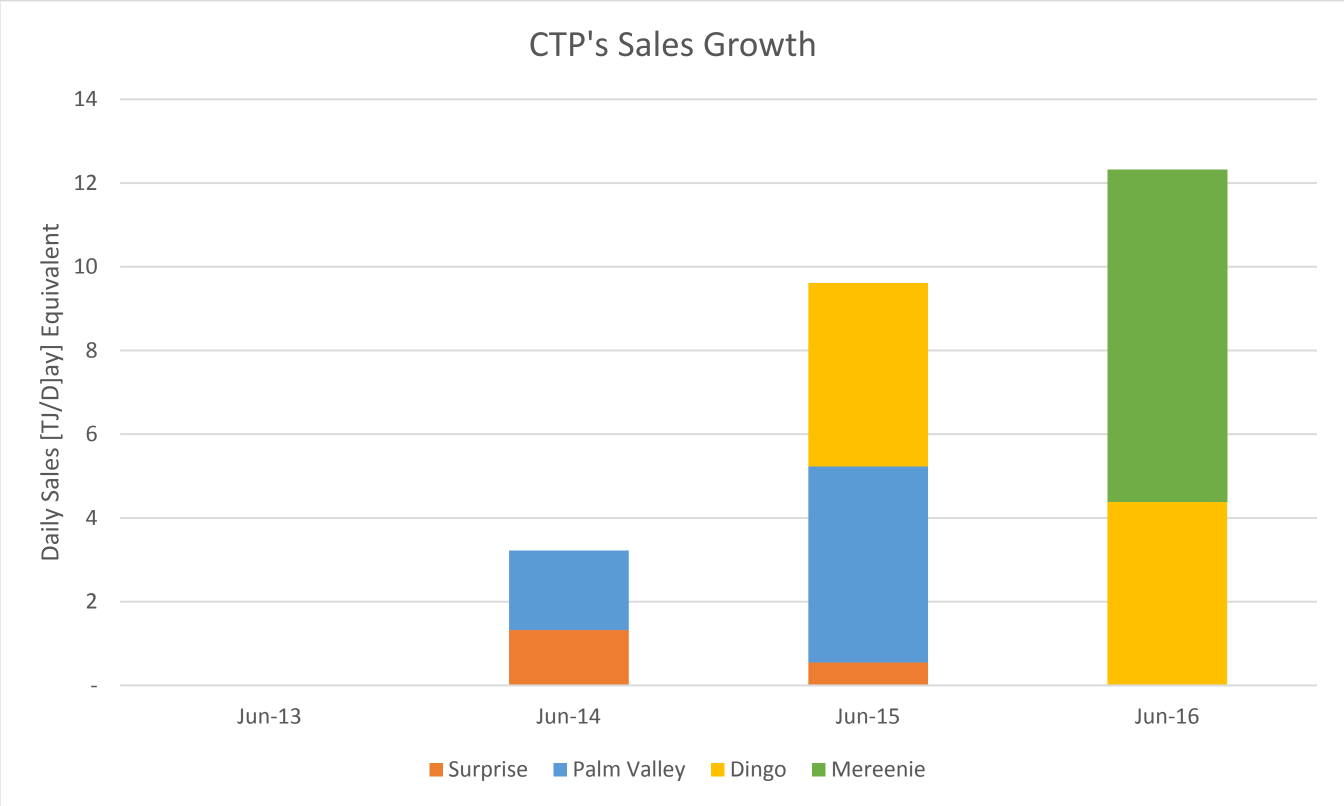
	2016 $ million	2015 $ million
Statutory loss after tax	(21.04)	(27.73)
Add/(less):		
One-off operating expenses (bonus restructuring)	1.73	—
R&D refunds	—	(7.32)
Impairment of exploration assets	1.40	6.57
Impairment of oil producing properties	0.04	5.42
Impairment of real property	—	0.10
Underlying loss after tax	**(17.87)**	(22.96)

Financial Review

The Company continued its transformation from an exploration company to an exploration and production company during the year ended 30 June 2016. Underlying loss improved by 22% on the previous financial year, reflecting a 10-month contribution from the Mereenie assets to the full year result.

Key Metrics	2016	2015	Percentage Change*
Net Sales Volumes			
Oil (barrels)	98,635	53,925	83%
Natural Gas (TJ)	3,230	1,194	171%
Average realised oil price (A$ per barrel)	58.15	92.93	(37%)
Sales revenue ($ million)	22.64	10.31	120%
Underlying Loss ($ million)	(17.87)	(22.96)	22%
Statutory loss (after tax)	(21.04)	(27.73)	24%
Cash ($ million)	15.11	3.52	329%

* *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

EBITDAX

Underlying earnings before interest, tax, depreciation, amortisation, impairment and exploration expense (EBITDAX[1]) increased to $2.86 million, compared to a loss of $8.84 million in the prior year. The result reflects the positive (10-month) contribution of the Mereenie assets to the full year result, partly offset by lower crude oil prices.

A reconciliation of underlying EBITDAX is shown below.

	2016 $ MILLION	2015 $ MILLION
Underlying loss after tax	(17.87)	(22.96)
Add/(less):		
Net interest	8.30	3.75
Income tax	—	—
Depreciation and amortisation	8.40	2.71
Underlying EBITDA	**(1.17)**	**(16.50)**
Exploration expense	4.03	7.66
Underlying EBITDAX[1]	**2.86**	**(8.84)**

[1] Earnings before Interest, Taxation, Depreciation and Amortisation, Impairment and Exploration expense.

The resulting underlying EBITDAX of $2.86 million reflects a period of substantial transition in Central's operations. Gas sales from Dingo did not achieve full contracted volumes until December 2015. In addition, Dingo Take-or-Pay revenue of $2.8 million that was generated to 31 December 2015 was not recognised as revenue during the reporting period. This Take-or-Pay revenue was received in January 2016 and will be accounted for as revenue in future periods in accordance with the Group's revenue recognition policy (refer Note 1(e)(i)).

Sales Volumes

Sales volumes for both oil and gas increased substantially from 2015, reflecting the Mereenie acquisition effective 1 September 2015.

Surprise oil field: The low oil prices and the remoteness of the Company's Surprise oil field led to the decision to temporarily shut-in oil production from this field in August 2015 to allow the Company to assess the re-charge potential of the field. Should oil prices recover significantly in $A terms, production can recommence after assessing the pressure build-up.

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 the year, with contracts being delivered from the Mereenie and Dingo fields.

Dingo gas field: The PWC GSA (Power and Water Corporation Gas Sales Agreement) commenced on 1 April 2015, but was constrained awaiting the customer's physical tie-in to the Dingo delivery point. For the 3-month period following commencement of the GSA on 1 April 2015, a total of 150 TJ was sold from the Palm Valley gas field. In accordance with the PWC GSA, revenue associated with Take-or-Pay during the 2015 calendar year was received in January 2016 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 decline in world crude oil prices, and partly offset by a lower Australian dollar, the average realised price per barrel of oil declined 37% on the previous financial year. In financial terms, this represented a reduction in revenue of approximately $3.4 million based on 2016 oil sales.

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

Other Income

In fiscal year 2015, Research and Development refunds totalling $7.32 million were recognised as income, arising largely from exploration activities in the Southern Georgina and Southern Amadeus basins. The 2015 income amount included refunds in respect of the financial year ended 30 June 2014 of $3.25 million and $4.07 million in respect of the financial year ended 30 June 2015, which was recognised as a receivable at 30 June 2015 and was received in September 2015. No Research and Development refunds are recognised in income in the Profit and Loss for the year ended 30 June 2016.

General and Administrative Expenses

General and administrative expenses net of recoveries decreased from $1.94 million in fiscal year 2015 to $0.5 million in fiscal year 2016. The decrease was a result of cost savings implemented in response to the lower oil prices and increased recoveries from both sole and joint venture operations generated by increased activity and Operatorship of the Mereenie assets effective from 1 September 2015.

Employee Benefits and Associated Costs

Employee costs, net of recoveries to Operational and Exploration activities, decreased to $4.48 million from $5.02 million in the previous financial year. The decrease reflects increased recoveries and productivity arising from the Mereenie acquisition.

Cash

At 30 June 2016, consolidated cash and cash equivalents available totalled $15,115,699 (2015: $3,516,139), including $676,283 (30 June 2015: $12,330) held in joint venture bank accounts.

Gearing

The consolidated debt ratio at 30 June 2016 was 0.56 (2015: 0.55). Debt ratio is defined as Total Debt / Total Assets. The Consolidated Entity's debt funding is supported by long-term gas sales contracts.

Capital Expenditure

Capital expenditure, excluding the Mereenie asset acquisition, was $2.86 million, down from $20.85 million in 2015. The 2016 capital expenditure related largely to ongoing stay in business expenditure. The 2015 capital expenditure related largely to construction of the Dingo facilities and pipeline.

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.

	2016 $ MILLION	2015 $ MILLION	2014 $ MILLION	2013 $ MILLION	2012 $ MILLION
Financial Data					
Operating revenue	23.86	10.31	3.72	—	—
Exploration expenditure	4.03	7.66	4.66	6.98	18.72
Loss after income tax	21.04	27.73	10.86	9.28	26.36
Equity issued during year	11.52	5.56	24.97	7.56	23.60
Property, plant and equipment	113.78	58.58	46.27	1.28	1.78
Borrowings	(85.70)	(47.46)	(23.76)	—	—
Net Assets (Total Equity)	16.52	23.15	43.07	24.65	24.20
Net Working Capital	5.33	(4.41)	2.78	4.93	10.64
Operating Data					
Gas Sales (GJ)	3,230,473	1,194,153	267,328	—	—
Oil Sales (barrels)	98,635	53,925	17,489	—	—
No. of employees at 30 June	83	58	51	26	17

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.

Over the past year, Central has substantially increased operating activities, notably in the production and sale of oil and gas. Central's operations have a significantly different risk profile compared to exploration. 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.

Access to the east coast gas market, in part, depends upon negotiating reasonable tariffs with the various monopoly pipeline owners. The approach to determining tariffs is currently subject to extensive review by Federal Government agencies. The outcome of these reviews will be material to Central's capacity to access the east coast gas market on reasonable terms.

Business Strategy

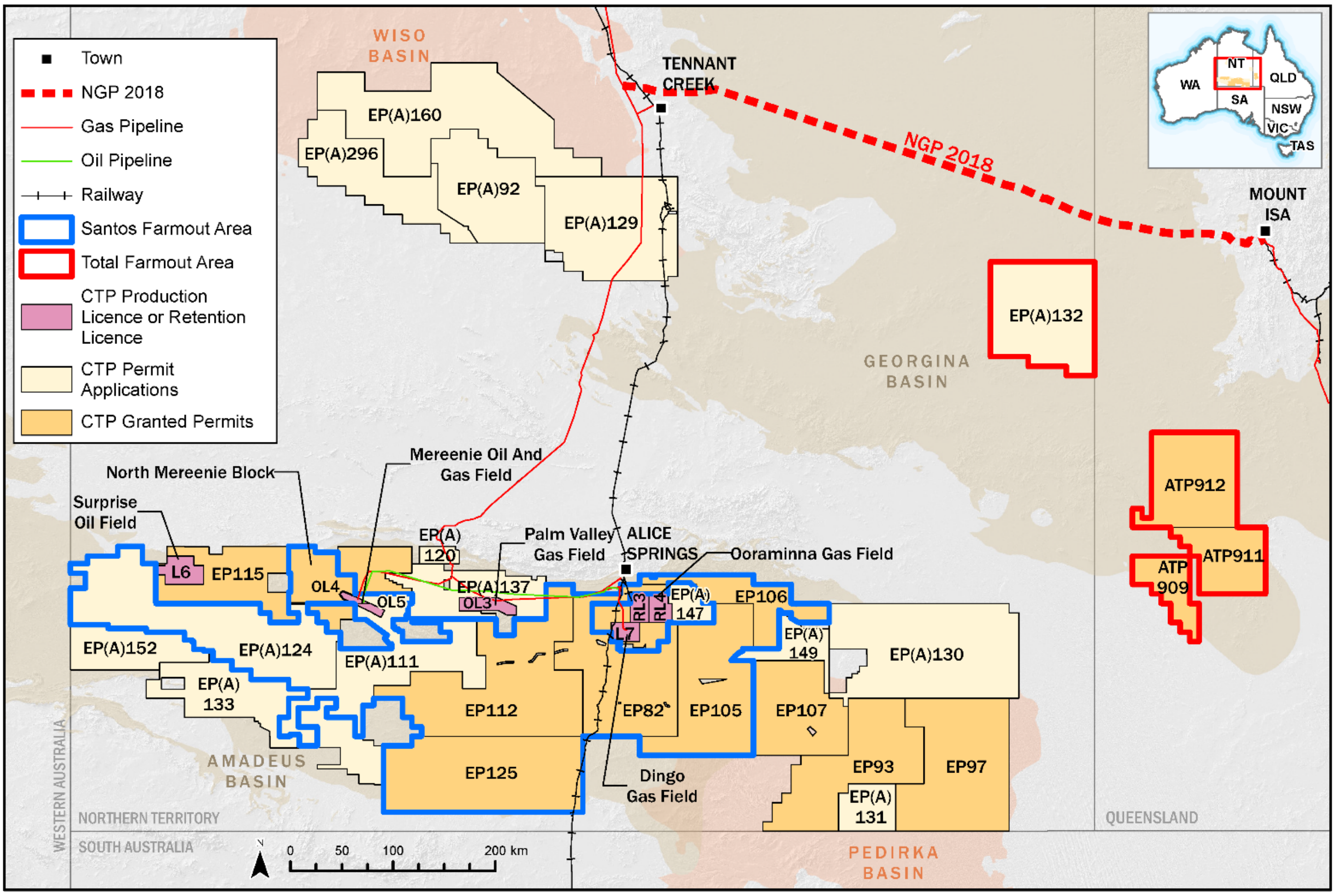
Over the past three years, Central has developed and successfully pursued a strategy to take advantage of a tightening domestic gas market to gain critical mass in conventional gas production and uncontracted gas reserves. This strategy first crystalised through the acquisition of the Palm Valley and Dingo gas fields from Magellan in April 2014, marking Central's entry into commercial gas production culminating in the acquisition of a 50% interest in the Mereenie oil and gas field.

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 and growing uncontracted conventional gas reserves from proven fields and has between 175 PJ and 300 PJ of uncontracted reserves (gross field basis) available in 2018 for the domestic gas shortfall, which should begin to bite in that year.

With 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 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, more recently, Mereenie have all been 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.

Creating new 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 portfolio now allows Central to generate critical free cash flow after debt service which can be applied towards high growth and value adding activities, notably initially targeting growing high value conventional gas reserves throughout our various exploration permits.



Granted Petroleum Permits, Licences and Application Interests

Operations and Activities

Palm Valley Gas Field (OL3)

Northern Territory
(CTP — 100% Interest)

Background

As a result of the acquisition of the Palm Valley gas field, effective 1 April 2014, the company commenced receiving revenue from gas sales. This shifted Central from an explorer to a multi-field producer in both oil and gas markets.

Performance

Gas production for the period 1 July 2015 to 30 June 2016 was 834,366.248 GJ.

Palm Valley provided gas to support Dingo and Mereenie gas contracts during annual statutory shut-down, which was a total of 45.54 TJ.

A review of the field performance was conducted, leading to an upgrade in outlook for gas production. Internationally recognised petroleum consultants Netherland, Sewell & Associates, Inc. ("NSAI") estimated petroleum reserves and contingent resources as announced to the ASX on 21 July 2015.

Two exploration targets within the licence area have benefited from a review of existing, and acquisition of, additional geological and geophysical data.

The **Palm Valley Deep prospect** has been firmed up with a drilling location selected. The objective is a test of the deeper Arumbera Sandstone, which is an established gas bearing reservoir in the Dingo gas field some 100 km eastwards. The target has a similar area to the producing gas pool in the Pacoota Sandstone.

The **Palm Valley West lead** has been updated with additional data collected from surface mapping. The initial results are positive, and the Company intends to conduct additional surface mapping to define the areal closure.

The **Yeti lead** has been defined by three 1965/66 seismic lines. The objective is to test the Stairway and Pacoota sandstones, which are established gas bearing reservoirs at the Palm Valley field to the west. The target has a similar areal closure to the Dingo gas field. Additional seismic surveying is required to confirm fold geometry and areal closure.

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

Northern Territory
(CTP — 100% Interest)

Background

The Ron Goodin Power Station in Alice Springs is slated for a 2017 shut-down to correspond to an increase in generating capacity at the Owen Springs Power Station. The Owen Springs plant is currently undergoing upgrades and should commence commissioning around year end. Once commissioning and power production ramp up at Owen Springs occurs, it is expected that Dingo field will operate at the 4.38 TJ/Day DCQ rate.

The Northern Territory Government granted the Dingo Petroleum Production Licence (L7) to Central on 7 July 2014. The production licence was converted from the retention licence (RL2).

The Dingo Pipeline Licence (PL30) was awarded by the Northern Territory Department of Mines and Energy on 19 July 2014.

The Dingo Gas Field Development was funded under a $30 million tranche of the loan facility agreement with Macquarie Bank and comprised construction of wellhead facilities, gathering pipelines, gas conditioning facilities, a 50 km gas pipeline to Brewer Estate in Alice Springs, and custody transfer metering facilities designed to service a gas sale contract with Power and Water Corporation of the Northern Territory providing gas to Owen Springs Power Station.

Performance

Construction of the pipeline was completed using innovative construction practices to add efficiency and reduce environmental footprint. Landowners, Traditional Owners and Environmentalists have reacted favorably to the project.

The strategic pipeline was a major milestone and signified the start of the Company being a significant player in the Northern Territory gas market. Central looks forward to playing an important role in inter-connecting Central Australia to the eastern seaboard gas network via the Northern Gas Pipeline ("NGP").

Dingo Gas processing plant during final commissioning early 2015

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. Production volume since that report is 19,364 ksm3 (from 15 December 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.

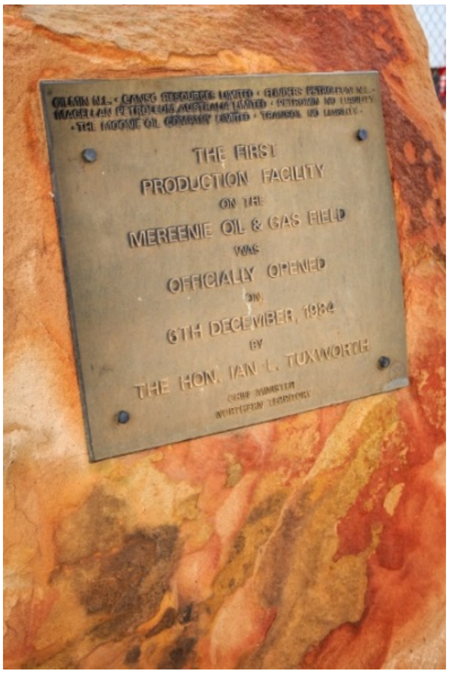
Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory
(CTP — 50% Interest, Santos — 50% Interest)

On 4 June 2015, Central announced its acquisition of a 50% interest in the Mereenie oil and gas field from Santos.

Background

The Mereenie oil and gas field was discovered in 1963 by the exploration well, Mereenie-1, which was drilled on the crest of a large surface expressed anticline, with subsurface field area up to ~25,000 acres, or 100 km^2. Hydrocarbon-saturated reservoirs of variable quality exist within the Stairway and Pacoota formations below the regional Stokes Siltstone seal. In most gas bearing reservoirs there is a gas saturated oil rim. The gross hydrocarbon column in the field is approximately 760 metres.



Gas production and export via pipeline to Darwin commenced in 1984, with flow rates increasing to a peak of ~53 TJ/d in 2005 before declining for contractual reasons. During the seven years from 1990 a further 20 "oil" wells were drilled, adding to gas production capacity, followed by six dedicated gas wells during 1999–2004, and four oil wells since 2007.

Following expiry of the long-term gas contract in 2009, the operator undertook studies and then acted in 2010 with the expansion of gas re-injection to enhance oil recovery. As of 2014, the field was producing up to 1,000 bopd (oil, condensate) from 23 wells, selling ~5 TJ/d gas (1.8 PJ pa) and reinjecting the balance into the oil reservoirs.

Gross production of 30 years to date is approximately 17 MMbbl oil, 258 PJ sales gas, and 1 MMbbl condensate.

With historical gas production of over 50 TJ/d, Mereenie can become a primary supplier of gas to the Eastern Seaboard via NGP.

Performance

Central continues to optimise the Mereenie operations receiving commendation from the Northern Territory Department of Mines and Energy ("NT DME"). "Central Petroleum is to be congratulated on its achievement of a safe and efficient transition to operator of the combined fields and their efforts to increase Indigenous and local employment".

Key activities in the assumption of operatorship included:

- Increasing local employment to 54%
- Increasing Traditional Owner employment to 26%
- Successfully completing the Annual Statutory shut-down to inspect vessels and test safety systems
- Reserve upgrades at Mereenie (as reported to the ASX)
- Stairway test at West Mereenie-15 demonstrated scope for reserve growth
- $1.5 million increase in local economic activity.

Eastern Satellite Station, Mereenie Field, Northern Territory

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(CTP — 90% Interest, Total — 10% interest)

Farmout

During Stage 1, the Joint Venture acquired and interpreted 974 km 2D seismic, which enabled the selection of drilling locations. Two exploration wells were drilled in the second half of 2014.

Should Total continue and fulfil its funding obligations for Stages 2 and 3, it will earn equity in increments to a total of 68% in the permits.

Central is operating the farmout areas for the first four years and, after completion of Stage 3, Total will assume operatorship for 90% of the area. Central will retain operatorship of the upstream activities on the remaining 10% of the area. The joint venture partners (Central and Total) have agreed to suspend exploration investment until oil prices rebound.

Evaluation

Data collected during Stage 1 includes laboratory analyses of core from Gaudi-1 and of core taken in offset wells, and is complete. Analytical results have been integrated with interpreted logs and revised depth maps. This allows for regional trend mapping by using the following geologic attributes: porosity, thermal maturity, and total organic carbon ("TOC") etc. These provide insight into the unconventional Lower Arthur Creek shale gas play, as well as new plays which have been revealed in the middle Cambrian succession.

The exploration targets in the joint venture's permits are now expanded to include:

1. Shale and tight gas reservoirs within the Lower Arthur Creek Formation, as targeted by Gaudi-1.

2. A potential structurally controlled Hydrothermal Dolomite ("HTD") play. Global analogues for this type of play are characterised by the highly localised creation of porosity in otherwise tight carbonates by the movement of hot geothermal fluids through the succession, upwards along faults. The types of mineralisation observed in the Gaudi-1 and nearby mineral well cores, the lost circulation in Whiteley-1, and anomalies observed on seismic, all provide evidence for the possible presence of this play within the joint venture's permits.

3. A conventional structural play within the Thorntonia Limestone in the shallower areas in the north of the Queensland permits. This is supported by source rock and oil analysis of nearby core hole 11005, which shows some of the best oil prone source rock properties in the Thorntonia in the basin, and on our current understanding of maturing trends within the ATPs.

4. A Neoproterozoic fault block play within a previously unimaged rift sequence locally developed below Cambro-Ordovician carbonates to the East of the ATPs. The inferred sequence was imaged as part of Central's 2013 seismic campaign in the basin. Internal reflectivity suggests the rift succession is likely to contain clastic as well as carbonate lithologies, which may provide effective reservoir objectives. The source rock potential of the succession is unknown.

The joint venture is considering various options to progress evaluation of these plays, and seeks additional play types and targets which may exist in these large permits.

Future Drilling Plans

Whiteley-1 Well

The joint venture is encouraged by the evaluation detailed above, and believes Whiteley-1 may be ideally located, as estimated from various geologic parameters. An operational plan has been prepared to enable re-entry of Whiteley-1 so we may test the tight gas play, and several secondary targets. The primary objectives are targeted to be fully cored and sampled for gas desorption and reservoir properties, in addition to an extensive logging program.

Southern Amadeus Basin

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

Santos Farmout

Under a three stage farmout agreement, Santos funded exploration in Stage 1 by investing an initial $30 million, with options to invest further in Stage 2 and Stage 3. In return, Santos would earn rights to up to 70% of the area totalling nearly 80,000 square kilometres. Santos assumed operatorship during exploration and, in the event that they are developed, Central will benefit from a free carry during the farmout period.

Central and Santos concurred that the prospectivity of the Southern Amadeus was confirmed by the results of Mt Kitty and the 1,587 km of 2D seismic acquired during Stage 1 of the farmout. As a result, Santos elected in July 2014 to proceed to Stage 2 of an amended Southern Amadeus Joint Venture with Central, where 1,300 km 2D seismic will be acquired across areas of highest prospectivity, earning Santos a 40% participating interest in permits listed in the table below (the "Southern Amadeus Joint Venture").

Wildlife in the Amadeus Basin

Stage 2

The Operator (Santos) has completed an integrated analysis of seismic, potential field (gravity and magnetics) and historic well data. This work was reviewed by Central and recommendations regarding seismic line layout and acquisition parameters were put forward to Santos. Santos has now completed the design of the Stage 2 seismic program with a line layout that targets identified leads, and with optimised recording and processing parameters that are aimed at improving imaging of the sub-salt. The joint venture's exploration endeavours in this and surrounding permits will focus on maturing large sub-salt leads to a drillable status through the acquisition of the Stage 2 seismic. The primary reservoir objective is the Heavitree Quartzite. Secondary reservoir objectives, also within the Neoproterozoic succession, include fractured basement, the Areyonga Formation, and the Pioneer Sandstone, which is gas productive in the currently sub-commercial Ooraminna field.

SOUTHERN AMADEUS AREA	TOTAL SANTOS PARTICIPATING INTEREST AFTER COMPLETION OF STAGE 1	TOTAL SANTOS PARTICIPATING INTEREST AFTER COMPLETION OF STAGE 2
EP 82 (excl. EP 82 Sub-Blocks)	25%	40% (i.e. additional 15% earned)
EP 105	25%	40% (i.e. additional 15% earned)
EP 106	25%	40% (i.e. additional 15% earned)
EP 112	25%	40% (i.e. additional 15% earned)

Surprise Oil Field (L6)

Northern Territory
(CTP — 100% Interest)

Background

In February 2014, Central was granted the Petroleum Production Licence (L6) for the Surprise Oil Field Development. This was the first production licence offered in onshore Northern Territory since the passing of the *Native Titles Act 1993* and was an important milestone not only for Central but also for the Northern Territory and the Traditional Owners.

Initial production and storage facilities were installed to allow production to commence from the Surprise West well in March 2014.

The installation of additional storage tanks and ancillary equipment was completed in 2015.

Performance

The Surprise West well produced approximately 88,650 barrels of oil since commencing production in March 2014 to August 2016.

The Surprise West well was a valuable cash-flow contribution to the Company. Currently the well is shut in due to low oil prices and to obtain long term pressure data.

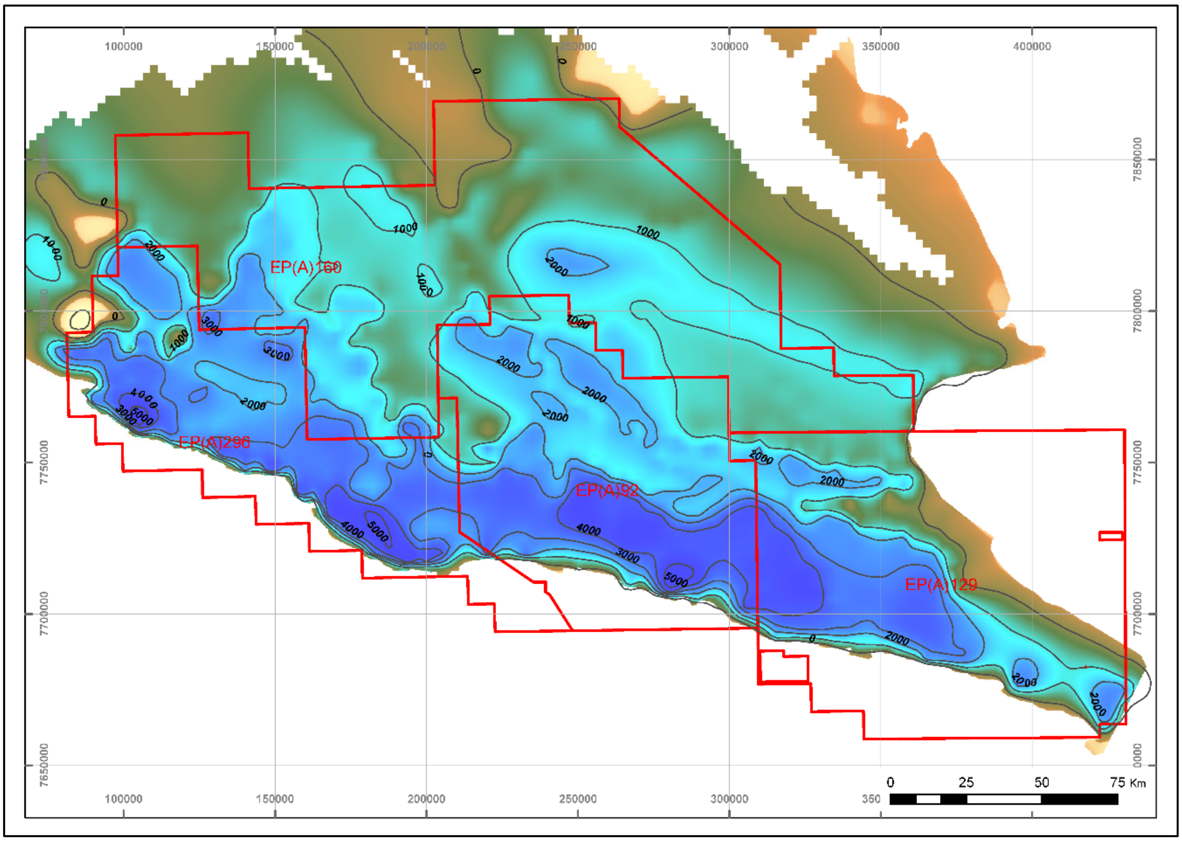
Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 86)

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 lead 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

Significant changes in the state of affairs of the Group during the financial year were as follows.

Contributed equity increased by $11,516,350 (from $160,785,182 to $172,301,532) as the result of a share placement to institutional investors in November 2015 (55.3 million shares at 19 cents per share) and a security purchase plan in December 2015 (9.2 million shares at 19 cents per share). Details of the changes in contributed equity are disclosed in Note 20 to the Financial Statements.

On 1 September 2015, the Group acquired a 50% interest in the Mereenie oil and gas field and assumed operatorship of the field. Details of the acquisition are disclosed in Note 30 to the Financial Statements. At the same time the Group's Loan Facility with Macquarie Bank was expanded (refer Note 34(e)).

EVENTS SINCE THE END OF THE FINANCIAL YEAR

No 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

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 as well as ASX and Chairman of TSX listed Orocobre Limited. He is also a non-executive director of ASX listed Primary Health Care 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. Within the last three years, Mr Cottee has not been a director of any other listed public company.

Wrixon F Gasteen BE (Hons), MBA (Dist)

Independent Non-executive Director [2]

Mr Gasteen is currently an Executive Director Asia Pacific for cyber-security company Votiro and is based in Singapore. As CEO and director of Hong Leong Asia, listed on the Singapore Stock Exchange (SGX: HLA), he transformed the company through acquisitions and organic growth. The result was a highly profitable conglomerate with $2.2 billion in sales, 80% of which were in China. 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. He has some 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. Mr Gasteen resigned from the board of ASX listed Sino Australia Oil & Gas as a non-executive director in November 2015. Within the last three years, Mr Gasteen has not been a director of any other listed public company.

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

Independent Non-executive Director

Prof. Peter S Moore has over thirty years of 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, Executive Director, Strategic Engagement for the Curtin Business School (part time), Chair of ESWA (Earth Sciences WA), a member of the Elsevier's Oil & Gas Advisory Board, Chair of the Curtin Graduate School of Business Advisory Board and a member of Curtin University's Faculty of Science and Engineering Advisory Council. Within the last three years, Prof. Moore has not been a director of any other listed public company.

Andrew P Whittle BSc (Hons)

Independent Non-executive Director

Mr Whittle was appointed to the Central Board on 25 April 2012 and was Chairman from 12 March 2013 to 31 July 2015 and remained a director until his retirement on 2 November 2015.

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. 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	9	9	5	5	4	4
Andrew Whittle[1]	4	4	2	2	—	—
Richard Cottee	9	9	—	—	—	—
Wrixon Gasteen	9	9	5	5	4	4
J Thomas Wilson	9	7	3	3	—	—
Peter Moore	9	9	—	—	4	4

1 *Resigned 2 November 2015*

REALISED REMUNERATION OF DIRECTORS AND KEY MANAGEMENT PERSONNEL FOR THE 2016 YEAR

The directors consider the remuneration information contained within the tables presented in the statutory remuneration report (pages 20 to 31) may give a distorted view of the true remuneration realised by the directors and key management personnel for the 2016 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[2] $	Termination benefits $	Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Andrew Whittle[1]	12,008	—	17,800	—	28,516	58,324	100%	—	58,324
Wrixon Gasteen	82,500	—	19,777	—	7,837	110,114	100%	—	110,114
Robert Hubbard	115,500	—	—	—	10,972	126,472	100%	—	126,472
J Thomas Wilson	68,250	—	—	—	—	68,250	100%	—	68,250
Peter Moore	89,333	—	—	—	8,487	97,820	100%	—	97,820
Sub-total	367,591	—	37,577	—	55,812	460,980	100%	—	460,980
Executive Directors & Key Management Personnel	Salary / fees $	STIP $	Non-monetary benefits[2] $		Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Richard Cottee	584,538	—	10,574	—	19,308	614,420	100%	—	614,420
Michael Herrington	473,716	22,000	26,418	—	37,548	559,682	100%	—	559,682
Daniel White	388,048	17,000	7,389	—	33,048	445,485	100%	—	445,485
Leon Devaney	400,085	34,000	8,629	—	31,837	474,551	100%	—	474,551
Michael Bucknill[3]	231,305	3,500	7,389	116,923	20,599	379,616	100%	—	379,616
Robbert Willink	183,077	3,500	—	—	17,725	204,302	100%	—	204,302
Sub-total	2,260,769	80,000	60,399	116,923	160,065	2,678,056	100%	—	2,678,056
Total Remuneration	**2,628,360**	**80,000**	**97,976**	**116,923**	**215,877**	**3,139,036**	**100%**	—	**3,139,036**

1 *Mr Whittle resigned as director 2 November 2015*
2 *Fringe benefits include loan fringe benefits relating to deferred director option fees and employee car parking fringe benefits*
3 *Mr Bucknill's position was made redundant effective 26 February 2016*

ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation with regard to its exploration activities.

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 2016 (58 at 30 June 2015).

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	
	2016	2015
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	17,628	8,500
Excise consulting services	4,500	48,957
Other tax related services	19,019	68,354
	41,147	**125,811**
(ii) Other services		
Magellan transaction due diligence	—	22,000
Mereenie transaction due diligence	90,999	—
Technical accounting advice on major transactions	27,181	—
Employee related services	—	6,698
	118,180	**28,698**
Total remuneration for non-audit services	**159,327**	**154,509**

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 32.

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 2016 outlines the remuneration arrangements of the Group in accordance with the requirements of the *Corporations Act 2001 (Cth), as amended (the Act).* This information has been audited as required by section 308(3C) of the Act.

The remuneration report is presented under the following sections:

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

A. Directors and Key Management Personnel

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

Directors

Robert Hubbard	Non-executive Chairman	
Richard Cottee	Managing Director and Chief Executive Officer	
Wrixon Gasteen	Non-executive Director	
J Thomas Wilson	Non-executive Director	(to 15 July 2016)
Peter Moore	Non-executive Director	
Andrew Whittle	Non-executive Director	(to 2 November 2015)

Other Key Management Personnel

Leon Devaney	Chief Financial Officer	
Michael Herrington	Chief Operating Officer	
Daniel White	Group General Counsel and Company Secretary	
Robert Willink	Exploration Advisor	
Michael Bucknill	General Manager Exploration	(to 26 February, 2016)

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.

Australia continues to be in a significant contraction of the resource sector as commodity prices remain at multi-year lows and the outlook for most commodity markets remains clouded due to concerns over global growth. Since October 2014, the energy sector has been under increasing financial pressure, largely due to the collapse in oil prices as well as gas pricing linked to oil. This has had a profound impact on all energy sector participants. In respect of this market dynamic, the CEO positioned the Company's focus on restoring value for shareholders by reducing costs, driving operational efficiency and prudently managing capital and targeting non-oil linked gas pricing.

Coupled with the Company having undertook a suspension of its 2015 pay reviews and with current reduced inflation rates and downward wage pressures within the energy sector and market peers freezing salaries, reducing work hours and implementing comprehensive redundancy programs, Central has taken a conservative view of the 2016 pay reviews. A genuine effort has been made, where appropriate, to compensate employees for inflation given the observations of the market and the present economic climate. With these factors considered, Central has retained in principle a suspension of pay rises with the exception of awarding where appropriate an inflation salary increase of 0.5% or on account of a change in position or other extenuating circumstances. In addition, the Company has achieved a solid result in comparison to its peer group in the energy market. This was reflected in the achievement of Corporate KPI's against Central Petroleum's Short Term Incentive Plan.

Inflation Salary increases of 0.5%	Where appropriate, a pay rise was awarded to address inflation and on account of a change in position or other extenuating circumstances.
Reduced STIP	The Company's Short Term Incentive Plan was scheduled for payment in July 2016, with the Board exercising its discretion to reduce the payment.
Nil LTIP Vesting	There were no awards that vested under the new Long Term Incentive Plan with it coming into its third year of implementation.

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 exploration industry. Accordingly, the Company has revamped its remuneration practices and, in particular, its short term and long term incentive plans with 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"). These changes were effective from 1 July 2014.

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 2016, 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 Vesting Percentage (the percentage of Share Rights which will vest 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.

With the effective date of 1 July 2014 onwards, all eligible employees subscribed to the new LTIP and, in doing so, waived their eligibility rights to participate in the incentive Options scheme.

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 (KPI's) 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 KPI's in the matrix being met at the 100% level. The KPI's 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 2015/16.

Key terms and conditions

The 2015/2016 STIP has been holistically designed to recognise and reward individual effort through connecting individual KPI's, departmental KPI's and corporate KPI's. These groups of KPI's are intrinsically linked and start by cascading from the corporate KPI's, to the departmental KPI's and then onto individual KPI's. Individual KPI's drive the success of achieving departmental KPI's, which are in turn aimed at effecting the desired outcome to be reached in the corporate KPI's.

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

The managing director approves KPI's after consultation with the Board. These KPI's 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 KPI's	30%	30%
Safety and Environment	10%	10%
Departmental KPI's	40%	30%
Individual KPI's	20%	30%

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

The 2015/2016 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 KPI's 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 2015/2016 Plan Year STIP.

Corporate KPI's included:

OBJECTIVE	WEIGHTING	100%	75%	50%
Promote and progress the NGP project through reserve upgrades	33%	≥420PJ*	≥280PJ	≥260PJ
Budgetary control	33%	Ensure expenditure remains within budget and costs minimised whilst still achieving approved scope of works		
Funding	33%	Cover Mereenie deferred acquisition payment by way of capital raising, farm-outs or other cost saving initiatives		

**Board discretion above 350PJ subject to final route and drilling options*

Safety and Environment KPI's included:

OBJECTIVE	WEIGHTING	100%	75%	50%
Traditional Owner cultural heritage: No breach	20%	Zero	1 of less than 2 days	Default
Safety: No Lost Time Injuries (LTI)	30%	Zero	1 of less than 2 days	Default
Environment: No breach regarding reportable environmental incidents	30%	Zero		
Training and Employment of Traditional Owners	20%	Two trained, two employed	Two trained, one employed	Two trained

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 KPI's which are re-set annually.

Individual KPI's are linked to the departmental KPI's 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).

G. Remuneration Details

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 (At Risk)		
		Salary / fees $	Cash STI $	Non-monetary benefits[1] $	Superannuation contributions $	Termination Benefits $	LSL $	Options & Rights[5] $	Total $	Value of Options as Proportion of Remuneration %
Non-Executive Directors										
Andrew Whittle[2]	2016	12,008	—	17,800	28,516	—	—	74,759	133,083	56%
	2015	102,667	—	10,799	9,753	—	—	99,124	222,343	45%
William Dunmore[3]	2016	—	—	—	—	—	—	—	—	—
	2015	27,083	—	—	—	—	—	—	27,083	0%
Wrixon Gasteen	2016	82,500	—	19,777	7,837	—	—	73,613	183,727	40%
	2015	67,500	—	11,999	—	—	—	110,138	189,637	58%
Robert Hubbard	2016	115,500	—	—	10,972	—	—	—	126,472	0%
	2015	72,000	—	—	6,840	—	—	—	78,840	0%
J Thomas Wilson	2016	68,250	—	—	—	—	—	—	68,250	0%
	2015	58,500	—	—	—	—	—	—	58,500	0%
Peter Moore	2016	89,333	—	—	8,487	—	—	—	97,820	0%
	2015	72,000	—	—	6,840	—	—	—	78,840	0%
Sub-total	2016	367,591	—	37,577	55,812	—	—	148,372	609,352	24%
	2015	399,750	—	22,798	23,433	—	—	209,262	655,243	32%
Executive Directors and Other Key Management Personnel										
Richard Cottee[4]	2016	609,146	—	10,574	19,308	—	9,391	1,543,173	2,191,592	70%
	2015	561,976	—	20,319	5,985	—	12,398	1,887,313	2,487,991	75%
Michael Herrington[3]	2016	468,514	22,000	26,418	37,548	—	10,919	124,022	689,421	18%
	2015	506,102	—	12,494	36,572	—	9,214	91,152	655,534	14%
Daniel White	2016	396,947	17,000	7,389	33,048	—	8,594	37,119	500,097	7%
	2015	397,106	—	1,826	30,000	—	10,972	(8,373)	431,531	0%
Bruce Elsholz[6]	2016	—	—	—	—	—	—	—	—	0%
	2015	120,520	—	1,694	22,556	—	2,212	(11,768)	135,214	0%
Leon Devaney	2016	419,561	34,000	8,629	31,837	—	11,647	46,410	552,084	8%
	2015	361,706	—	1,694	27,780	—	6,830	(5,165)	392,845	0%
Michael Bucknill[7]	2016	218,666	3,500	7,389	20,599	116,923	(6,820)	(4,848)	355,409	0%
	2015	330,641	—	1,694	32,048	—	4,260	(5,271)	363,372	0%
Robbert Willink	2016	154,085	3,500	—	17,725	—	5,136	7,752	188,198	4%
	2015	349,810	—	—	32,300	—	4,553	(6,877)	379,786	0%
Sub-total	2016	2,266,919	80,000	60,399	160,065	116,923	38,867	1,753,628	4,476,801	39%
	2015	2,627,861	—	39,721	187,241	—	50,439	1,941,011	4,846,273	40%
Total Remuneration	**2016**	**2,634,510**	**80,000**	**97,976**	**215,877**	**116,923**	**38,867**	**1,902,000**	**5,086,153**	**37%**
	2015	**3,027,611**	**—**	**62,519**	**210,674**	**—**	**50,439**	**2,150,273**	**5,501,516**	**39%**

1 *Represents fringe benefits tax.*
2 *Mr Whittle resigned as director 2 November 2015.*
3 *Mr Dunmore and Mr Herrington retired as directors 26 November 2014.*
4 *Freestone Energy Partners Pty Ltd ("FEP") provided the services of Richard Cottee on the basis of a secondment up to 29 June 2015.*
5 *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.*
6 *Mr Elsholz resigned from employment on 30 November 2014.*
7 *Mr Bucknill's position was made redundant 26 February 2016.*

The fair values of deferred share rights granted during 2016 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
14 Oct 15	05 Jan 21	$0.1460	Nil	$0.190	80%	2.05%	0.00%
22 Dec 15	05 Jan 21	$0.0845	Mil	$0.165	87%	2.22%	0.00%
22 Dec 15	09 Feb 21	$0.1230	Nil	$0.165	87%	2.22%	0.00%

The values disclosed for 2015 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
1 Jul 14	11 Nov 15	$0.0200	$0.400	$0.320	45% to 65%	2.54%	
9 Apr 15	15 Nov 17	$0.0033	$0.475	$0.125	55% to 75%	1.74%	
9 Apr 15	15 Nov 17	$0.0062	$0.450	$0.125	55% to 75%	1.74%	
9 Apr 15	15 Nov 17	$0.0067	$0.400	$0.125	55% to 75%	1.74%	

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

		NUMBER OF OPTIONS GRANTED	GRANT DATE	AVERAGE FAIR VALUE AT GRANT DATE	AVERAGE EXERCISE PRICE PER OPTION	EXPIRY DATE	NUMBER OF OPTIONS VESTED	PROPORTION OF OPTIONS VESTED
Non-Executive Directors								
Andrew Whittle[1]	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
William Dunmore[2]	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Wrixon Gasteen	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Robert Hubbard	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
J Thomas Wilson	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Peter Moore	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Executive Directors and Other Key Management								
Richard Cottee	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Michael Herrington[2,4]	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Daniel White	2016	—	—	—	—	—	—	—
	2015	450,000	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
Bruce Elsholz[3]	2016	—	—	—	—	—	—	—
	2015	370,500	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
Leon Devaney	2016	—	—	—	—	—	—	—
	2015	504,000	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
Michael Bucknill[5]	2016	—	—	—	—	—	—	—
	2015	100,000	01 Jul 14	$0.0200	$0.400	15 Nov 15	100,000	100%
	2015	330,000	9 Apr 15	$0.0067	$0.400	15 Nov 17	—	—
Robbert Willink	2016	—	—	—	—	—	—	—
	2015	120,000	17 Jul 14	$0.0200	$0.400	15 Nov 15	120,000	100%
	2015	330,000	9 Apr 15	$0.0067	$0.400	15 Nov 17	—	—

1 *Mr Whittle resigned 2 November 2015.*
2 *Mr Dunmore and Mr Herrington retired as directors 26 November 2014.*
3 *Mr Elsholz resigned from employment on 30 November 2014. Options were awarded in respect of prior service periods.*
4 *During 2015, Mr Herrington had 450,000 options cancelled out of the 1,800,000 options granted in the prior year.*
5 *Mr Bucknill's position was made redundant 26 February 2016.*

Table 3: 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 OPTIONS VESTED
Non-Executive Directors								
Andrew Whittle[1]	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
William Dunmore[2]	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Wrixon Gasteen	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Robert Hubbard	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
J Thomas Wilson	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Peter Moore	2016	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—
Executive Directors and Other Key Management								
Richard Cottee	2016	1,913,873	22 Dec 15	$0.1230	$0.000	09 Feb 21	—	—
	2016	193,031	22 Dec 15	$0.0845	$0.000	05 Jan 21	—	—
	2015	—	—	—	—	—	—	—
Michael Herrington[2]	2016	930,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
	2015	—	—	—	—	—	—	—
Daniel White	2016	770,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
	2015	330,000	24 Jun 15	$0.074	$0.000	23 Sep 20	—	—
Leon Devaney	2016	783,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
	2015	278,571	24 Jun 15	$0.074	$0.000	23 Sep 20	—	—
Michael Bucknill[3]	2016	640,000	14 Oct 15	$0.146	$0.000	05 Jan 21	—	—
	2015	274,285	24 Jun 15	$0.074	$0.000	23 Sep 20	—	—
Robbert Willink	2016	—	—	—	—	—	—	—
	2015	262,286	24 Jun 15	$0.074	$0.000	23 Sep 20	—	—

[1] *Mr Whittle resigned 2 November 2015.*
[2] *Mr Dunmore and Mr Herrington retired as directors 26 November 2014.*
[3] *Mr Bucknill's position was made redundant 26 February 2016. All Rights were subsequently cancelled.*

Table 4: Shareholdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF OPTIONS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Andrew Whittle[1]	2016	236,044	N/A	—	—	—	236,044	N/A
	2015	133,680	N/A	102,364	—	—	N/A	236,044
Wrixon Gasteen	2016	97,000	N/A	39,473	—	—	N/A	136,473
	2015	97,000	N/A	—	—	—	N/A	97,000
Robert Hubbard	2016	120,000	N/A	178,947	—	—	N/A	298,947
	2015	64,100	N/A	55,900	—	—	N/A	120,000
J Thomas Wilson	2016	—	N/A	—	—	—	N/A	—
	2015	—	N/A	—	—	—	N/A	—
Peter Moore	2016	—	—	—	—	—	N/A	—
	2015	—	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2016	436,383	N/A	196,055	—	—	N/A	632,438
	2015	208,683	N/A	227,700	—	—	N/A	436,383
Michael Herrington[2]	2016	250,000	N/A	—	—	—	N/A	250,000
	2015	200,000	N/A	50,000	—	—	N/A	250,000
Daniel White	2016	288,000	N/A	—	—	—	N/A	288,000
	2015	288,000	N/A	—	—	—	N/A	288,000
Leon Devaney	2016	210,000	N/A	—	—	—	N/A	210,000
	2015	110,000	N/A	100,000	—	—	N/A	210,000
Michael Bucknill[3]	2016	56,000	N/A	—	—	—	56,000	N/A
	2015	31,000	N/A	25,000	—	—	N/A	56,000
Robbert Willink	2016	—	N/A	—	—	—	N/A	—
	2015	—	N/A	—	—	—	N/A	—

[1] *Mr Whittle resigned as director 2 November 2015.*
[2] *Mr Herrington retired as director 26 November 2014.*
[3] *Mr Bucknill's position was made redundant, effective 26 February 2016.*

Table 5: 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							
Andrew Whittle[1]	2016	900,000	—	—	—	900,000	N/A
	2015	900,000	—	—	—	N/A	900,000
Wrixon Gasteen	2016	1,000,000	—	—	(333,334)	N/A	666,666
	2015	1,000,000	—	—	—	N/A	1,000,000
Robert Hubbard	2016	—	—	—	—	N/A	—
	2015	—	—	—	—	N/A	—
J Thomas Wilson	2016	—	—	—	—	N/A	—
	2015	—	—	—	—	N/A	—
Peter Moore	2016	—	—	—	—	N/A	—
	2015	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel							
Richard Cottee	2016	34,584,407	—	—	(9,683,634)	N/A	24,900,773
	2015	34,584,407	—	—	—	N/A	34,584,407
Michael Herrington[2]	2016	2,250,000	—	—	(300,000)	N/A	1,950,000
	2015	2,700,000	—	—	(450,000)	N/A	2,250,000
Daniel White	2016	1,493,334	—		(733,334)	N/A	760,000
	2015	1,643,334	—	450,000	(600,000)	N/A	1,493,334
Leon Devaney	2016	1,064,000	—	—	(560,000)	N/A	504,000
	2015	560,000	—	504,000	—	N/A	1,064,000
Michael Bucknill[3]	2016	430,000	—	—	(100,000)	330,000	—
	2015	—	—	430,000	—	N/A	430,000
Robbert Willink	2016	450,000	—	—	(120,000)	N/A	330,000
	2015	—	—	450,000	—	N/A	450,000

[1] Mr Whittle retired, effective 26 November 2014.
[2] Mr Herrington retired as director 26 November 2014.
[3] Mr Bucknill's position was made redundant, effective 26 February 2016.

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	2016	666,666	—	—
	2015	1,000,000	—	333,333
Executive Directors and Other Key Management Personnel				
Richard Cottee	2016	24,900,773	—	—
	2015	34,584,407	—	9,683,634
Michael Herrington[1]	2016	1,950,000	—	—
	2015	2,250,000	—	300,000
Daniel White	2016	760,000	—	—
	2015	1,493,334	—	733,334
Leon Devaney	2016	504,000	—	—
	2015	1,064,000	—	560,000
Michael Bucknill[2]	2016	N/A	—	—
	2015	430,000	100,000	100,000
Robbert Willink	2016	330,000	—	—
	2015	450,000	120,000	120,000

[1] Mr Herrington retired as director 26 November 2014.
[2] Mr Bucknill's position was made redundant, effective 26 February 2016.

For each grant of options included in the Tables 1 to 5 above, the percentage of the grant that was vested and the percentage that was forfeited because the person did not meet the performance or service criteria 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	Year Granted	Vested %	Forfeited %	Financial Years in which Options may Vest	Maximum Value of Grant yet to Vest $
	SHARE BASED COMPENSATION BENEFITS (OPTIONS)				
Andrew Whittle[1]	2013	33	—	2013 to 2018	—
Wrixon Gasteen	2013	33	—	2013 to 2018	9,451
Richard Cottee	2013	28	—	2013 to 2018	1,640,268
Michael Herrington	2014	—	25	2014 to 2018	1,570
	2013	33	—	2013 to 2018	8,506
Daniel White	2015	—	—	2015 to 2018	587
	2014	100	—	—	—
	2012	100	—	—	—
Leon Devaney	2015	—	—	2015 to 2018	658
	2014	100	—	2014 to 2016	—
Michael Bucknill[2]	2015	23	—	2015 to 2018	—
Robbert Willink	2015	27	—	2015 to 2018	553

[1] Mr Whittle resigned as director 2 November 2015.
[2] Mr Bucknill's position was made redundant effective 26 February 2016.

Deferred Share Holdings of Key Management Personnel

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

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

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

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

Table 6: Deferred Share Holdings of Key Management Personnel

		NUMBER OF RIGHTS HELD AT START OF YEAR	MAXIMUM NUMBER GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	CONVERTED TO SHARES	NUMBER OF RIGHTS HELD AT END OF YEAR (UNVESTED)
Executive Directors and Other Key Management Personnel						
Richard Cottee	2016	—	2,104,904	—	—	2,104,904
	2015	—	—	—	—	—
Michael Herrington	2016	—	930,000	—	—	930,000
	2015	—	—	—	—	—
Daniel White	2016	330,000	770,000	—	—	1,100,000
	2015	—	330,000	—	—	330,000
Leon Devaney	2016	278,571	783,000	—	—	1,061,571
	2015	—	278,571	—	—	278,571
Michael Bucknill[1]	2016	274,285	640,000	(914,285)	—	—
	2015	—	274,285	—	—	274,285
Robbert Willink	2016	262,286	—	—	—	262,286
	2015	—	262,286	—	—	262,286

[1] Mr Bucknill's position was made redundant effective 26 February 2016

H. 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 $576,537 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 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.

Mike Herrington, Executive Director and Chief Operating Officer

- The term of the agreement expires 29 January 2019.
- Mr Herrington's base salary is presently $467,300 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 $393,460 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 term of the agreement expires 29 November 2017.
- Mr White's base salary is presently $386,900 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.

Michael Bucknill, General Manager, Exploration

- Mr Bucknill's employment was terminated on the basis of redundancy effective 26 February 2016.
- Mr Bucknill's base salary was $320,000 per annum. In addition, superannuation at 9.5% was applicable.

Robbert Willink, Exploration Advisor

- The term of the agreement expires 30 June 2017 with the exception that for the amount of time that Mr Willink's employment remains in abeyance, an equal equivalent amount of time shall be added to the duration of the original employment term, thus extending the end date of the current agreement.
- Mr Willink's employment status was changed to a part-time basis from 4 January and is currently in abeyance, effective from 1 March 2016.
- Mr Willink's base salary is presently $62,769 per annum based on current working arrangements when abeyance is not in effect. In addition, superannuation at 9.5% is applicable. The salary is reviewed annually.
- In order to terminate employment, a three week period of notice is required by either party (an additional one week period of notice is required to be provided by the Company), except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

I. 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 2016.

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 except for Mr Wilson, who resides outside of Australia.

Signed in accordance with a resolution of the directors:

Richard Cottee
Managing Director
Brisbane

21 September 2016

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2016, 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
21 September 2016

PricewaterhouseCoopers, ABN 52 780 433 757
480 Queen Street, BRISBANE QLD 4000, GPO Box 150, BRISBANE QLD 4001
T: +61 7 3257 5000, F: +61 7 3257 5999, www.pwc.com.au

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 2016 Corporate Governance Statement is dated as at 30 June 2016 and reflects the corporate governance practices in place throughout the 2016 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

FINANCIAL REPORT

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the review of operations and activities which forms part of the directors' report on pages 4 to 31. These pages are not part of these financial statements.

The financial statements were authorised for issue by the directors on 21 September 2016. 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 2016

	NOTE	**2016** **$**	2015 $
Revenue from the sale of goods	24(a)	22,642,569	10,313,266
Other revenue from customers	24(a)	1,220,000	–
Cost of sales		(14,060,704)	(10,117,038)
Gross profit		9,801,865	196,228
Other income	2	259,939	7,480,298
Share based employment benefits	33(d)	(2,235,544)	(2,246,683)
General and administrative expenses		(505,674)	(1,938,425)
Depreciation and amortisation	3(a)	(8,404,153)	(2,707,589)
Employee benefits and associated costs		(4,478,454)	(5,018,180)
Exploration expenditure		(4,025,627)	(7,655,931)
Restructure of future contingent commitments	3(b)	(1,725,000)	—
Finance costs	3(a)	(8,290,599)	(3,748,714)
Impairment expense	3(a)	(1,437,045)	(12,092,042)
Loss before income tax		(21,040,292)	(27,731,038)
Income tax credit	4	—	—
Loss for the year	22	(21,040,292)	(27,731,038)
Other comprehensive loss for the year, net of tax		—	—
Total comprehensive loss for the year		(21,040,292)	(27,731,038)
Total comprehensive loss attributable to members of the parent entity		**(21,040,292)**	(27,731,038)
Basic and diluted loss per share (cents)	23	(5.16)	(7.63)

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 30 JUNE 2016

	NOTE	2016 $	2015 $
ASSETS			
Current assets			
Cash and cash equivalents	6	15,115,699	3,516,139
Trade and other receivables	7	3,787,278	5,869,332
Inventories	8	3,592,561	2,136,673
Assets held for sale	9	—	1,755,736
Total current assets		22,495,538	13,277,880
Non-current assets			
Property, plant and equipment	10	113,783,254	58,577,415
Exploration assets	11	8,898,767	8,898,767
Intangible assets	12	82,393	12,052
Other financial assets	13	2,208,624	2,075,733
Goodwill	14	3,906,270	3,906,270
Total non-current assets		128,879,308	73,470,237
Total assets		**151,374,846**	**86,748,117**
LIABILITIES			
Current liabilities			
Trade and other payables	15	6,896,389	7,707,897
Deferred revenue	16	2,714,334	—
Interest-bearing liabilities	17	3,784,194	7,921,129
Provisions	18	3,766,713	2,060,330
Total current liabilities		17,161,630	17,689,356
Non-current liabilities			
Trade and other payables	15	2,621,694	—
Deferred revenue	16	1,253,074	—
Interest-bearing liabilities	17	81,916,860	39,536,722
Other financial liabilities	19	11,765,271	—
Provisions	18	20,138,707	6,375,539
Total non-current liabilities		117,695,606	45,912,261
Total liabilities		**134,857,236**	**63,601,617**
Net assets		**16,517,610**	**23,146,500**
EQUITY			
Contributed equity	20	172,301,532	160,785,182
Reserves	21	19,590,431	16,695,379
Accumulated losses	22	(175,374,353)	(154,334,061)
Total equity		**16,517,610**	**23,146,500**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2016

	CONTRIBUTED EQUITY $	RESERVES $	ACCUMULATED LOSSES $	TOTAL $
Balance at 1 July 2014	**155,223,040**	**14,448,696**	**(126,603,023)**	**43,068,713**
Total loss for the year	—	—	(27,731,038)	(27,731,038)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(27,731,038)	(27,731,038)
Transactions with owners in their capacity as owners				
Share based payments	—	2,246,683	—	2,246,683
Options issued for financing	—	—	—	—
Share and option issues	6,000,000	—	—	6,000,000
Share issue costs	(437,858)	—	—	(437,858)
	5,562,142	2,246,683	—	7,808,825
Balance at 30 June 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**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOW

FOR THE YEAR ENDED 30 JUNE 2016

	NOTE	2016 $	2015 $
Cash flows from operating activities			
Receipts from customers		26,674,618	10,980,363
Interest received		239,221	143,396
Other income		4,073,057	3,420,536
Interest and borrowing costs		(7,298,231)	(286,761)
Payments for restructuring future contingent commitments	3(b)	(1,725,000)	—
Payments to suppliers and employees (inclusive of GST)		(22,834,261)	(24,857,867)
Net cash (outflow) / inflow from operating activities	28	(870,596)	(10,600,333)
Cash flows from investing activities			
Payments for property, plant and equipment		(1,831,972)	(21,776,201)
Payments for interest in Mereenie Joint Venture		(47,073,161)	—
Proceeds from sale of property, plant and equipment		354,360	960,000
Redemption / (Acquisition) of security deposits and bonds		101,759	345,352
Net cash inflow / (outflow) from investing activities		(48,449,014)	(20,470,849)
Cash flows from financing activities			
Proceeds from the issue of shares and options		11,516,350	5,562,142
Proceeds from borrowings and other financing arrangements		53,025,000	19,000,000
Repayment of borrowings		(3,622,180)	(305,295)
Net cash inflow from financing activities		60,919,170	24,256,847
Net (decrease)/increase in cash and cash equivalents		**11,599,560**	**(6,814,335)**
Cash and cash equivalents at the beginning of the financial year		**3,516,139**	**10,330,474**
Cash and cash equivalents at the end of the financial year	6	**15,115,699**	**3,516,139**

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 consolidated financial statements of the Group have been prepared on a going concern basis, which contemplates continuity of business activities and realisation of assets and the settlement of liabilities in the ordinary course of business.

For the year ended 30 June 2016 the Group incurred a loss before tax of $21,040,292 (2015: $27,731,038), net cash outflow from operating activities of $870,596 (2015: outflow of $10,600,333) and as of that date, the Group's net current assets were $5,333,908 (2015: net current liabilities of $4,411,476). EBITDAX from oil and gas production activities was $9,877,081 (2015: $196,228). As at 30 June 2016 the Group had cash assets including joint arrangement balances amounting to $15,115,699 (2015: $3,516,139).

The Group continually monitors its cash flow requirements to ensure that it has sufficient funds to meet its contractual commitments and adjusts its spending, particularly with respect to discretionary exploration activity and corporate overhead, accordingly. The directors have also, during the year, undertaken a strategic review of the Group's operations and portfolio. The result of the strategic review has, amongst other things, led to a reduction in the Group's overheads and a number of initiatives to streamline the Group's business.

As supported by the cash assets at 30 June 2016, the Group will, over at least the next 12-months, have sufficient funds to meet its commitments and continue to pay its debts as and when they fall due and payable. This increase in cash assets was achieved primarily by a share placement and share purchase plan which resulted in additional equity funds of $12.2 million and the entering into a 5.2 PJ pre-paid gas sale agreement with Macquarie Bank Limited which also enabled the Company to fully fund the $10 million deferred purchase price for the Mereenie oil and gas field.

Notwithstanding the above, in order to maintain sustained cash flows over the longer term, the primary focus for the Company is to secure new Gas Sales Agreements ("GSA") in either the Northern Territory or east coast via the Northern Gas Pipeline ("NGP"), which is due for completion in 2018.

In the unlikely event that the Group experiences an unexpected shortfall in cash flows, several alternative sources of funding are available for consideration and the one which is most aligned with creating shareholder value at the time will be selected. In addition to accessing new supportable debt generated by new GSA's, two other notable sources of funding include a sell down of a partial interest in Central's existing producing assets (Mereenie, Palm Valley and Dingo) or approaching the equity markets for a capital raising. Alternatively, a combination of the above could be implemented depending on the prevailing economic and market conditions.

The directors believe that the Group will have sufficient funds throughout the next 12-months and will be able to meet its debts and commitments as they fall due and, accordingly, have prepared the Financial Statements on a going concern basis.

(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 2015 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

(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 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

(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 35.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 32(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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 13) 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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

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.

(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 24).

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions (continued)

(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.

(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

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(u) Contributed Equity

Ordinary shares are classified as equity.

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

(v) Dividends

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

(w) Earnings Per Share

(i) Basic Earnings Per Share

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

(ii) Diluted Earnings Per Share

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

(x) Goods and Services Tax (GST)

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

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

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

(y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 25, 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 tax consolidation legislation. The head entity, Central Petroleum Limited, and the controlled entities in the 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 standard permits a modified retrospective approach for the adoption. Under this approach, entities will recognise transitional adjustments in retained earnings on the date of initial application (e.g. 1 July 2017), i.e. without restating the comparative period. They will only need to apply the new rules to contracts that are not completed as of the date of initial application.

At this stage, the group is not able to estimate the impact of the new rules on the group's financial statements. The group will make more detailed assessments of the impact over the next 12-months. The group does not expect to adopt the new standard before 1 July 2017.

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 $1,691,141. However, 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.

(d) AASB 2014-3 Accounting for Acquisitions in Joint Operations

In August 2014, the AASB made limited scope amendments to AASB 11 Joint Arrangements to explicitly address the accounting for the acquisition of an interest in a joint operation. The amendments require an investor to apply the principles of business combination accounting when it acquires an interest in a joint operation that constitutes a business.

As required under the transitional provisions, the Group will apply the amendments prospectively to acquisitions occurring on or after 1 July 2016. They will therefore not affect any of the amounts currently recognised in the financial statements.

2. OTHER INCOME

	2016 **$**	2015 $
Interest	259,439	150,003
Research and development refunds (a)	—	7,324,496
Other	500	5,799
Total other income	**259,939**	**7,480,298**

(a) The 2015 amount includes refunds received during the year in respect of the financial year ended 30 June 2014 amounting to $3,251,940. It also includes $4,072,556 accrued as receivable in respect of the financial year ended 30 June 2015.

3. EXPENSES

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

	NOTE	2016 $	2015 $
Depreciation			
Buildings		290,229	844
Producing assets		2,070,567	1,047,939
Restoration assets		582,740	304,162
Plant and equipment		5,412,754	1,301,467
Leasehold improvements		27,812	42,880
Total depreciation		8,384,102	2,697,292
Amortisation			
Software		20,051	10,297
Impairment expense	3(b)	1,437,045	12,092,042
Other operating expenses	3(b)	1,725,000	—
Rental expense relating to operating leases – Minimum lease payments		984,026	1,224,562
Finance costs			
Interest charge on Macquarie debt facility		6,687,983	2,937,287
Interest paid to other suppliers		20,545	16,829
Interest on other financial liabilities		40,271	—
Borrowing costs on Macquarie and other debt facility		637,761	285,210
Amortisation of deferred finance costs		510,734	327,827
Accretion charge		393,305	181,561
		8,290,599	3,748,714

(b) Individually significant items

Impairment of Assets

Oil and gas producing assets

Impairment expense totalling $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.

During the 2015 year the Group fully impaired the assets relating to its oil producing assets in the Amadeus Basin. The impairment was based on expected future cash flows from the asset. The impairment loss included in the income statement relating to these assets was $5,420,293.

Property

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

During 2015, real property assets consisting of a warehouse and a residential property in Alice Springs were placed on the market for sale and were impaired to reflect their recoverable amounts. The impairment loss relating to these assets in the 2015 year was $100,822.

3. EXPENSES (CONTINUED)

Exploration assets

During the current 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.

During the 2015 year the following exploration permits were impaired to their recoverable amounts:

EP115 was impaired by $828,800. In light on the impairment of the oil producing assets this permit was impaired by 50% of its previous carrying value. Exploration and evaluation activities continue in the North Mereenie Block (operated by Santos) under a Farmout agreement with Santos.

EP97 impaired by $5,615,460. Management has impaired this asset to its likely recoverable amount under a potential divestment of the permit interests.

EP106 impaired by $126,667. Management has impaired this asset to $Nil on the basis of a likely relinquishment of the permit.

Restructure of future contingent commitments

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 has the effect of removing Central's net exposure to the Mereenie Production Bonus (refer Note 31(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.

(a) Income tax expense

	2016 $	2015 $
Current tax	–	–
Deferred tax	–	–
Income tax expense	–	–

4. INCOME TAX (CONTINUED)

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

	2016 $	2015 $
Loss before income tax expense	(21,040,292)	(27,731,038)
Prima facie tax benefit at 30% (2015: 30%)	6,312,088	8,319,311
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	66,390	(362,625)
Research and development expenditure	—	(2,714,864)
Share based payments	(670,663)	(674,005)
Non-assessable income	—	2,197,349
Sub-total	5,707,815	6,765,166
Under provision in prior year	—	—
Deferred tax assets not recognised	(5,707,815)	(6,765,166)
Recognition of previously unrecognised DTA	—	—
Income tax expense	—	—

(c) Amounts recognised directly in equity

	2016 $	2015 $
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	131,357
Deferred tax assets not recognised	(220,392)	(131,357)
Net amounts recognised directly in equity	—	—

(d) Tax Losses

	2016 $	2015 $
Unutilised tax losses for which no deferred tax asset has been recognised	112,459,194	109,823,407
Potential tax benefit at 30%	33,737,758	32,947,022

4. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2016 $	2015 $
Deferred tax assets		
Provisions and accruals	7,230,559	2,598,851
Financial liabilities	12,081	—
Future deductible expenditure	517,500	—
Blackhole expenditure	349,265	443,927
Borrowing costs	216,876	112,396
PRRT	201,315,062	52,254,331
Unutilised losses	42,834,869	37,756,625
Total deferred tax assets before set-offs	252,476,212	93,166,130
Set-off of deferred tax liabilities pursuant to set-off provisions	(10,720,341)	(6,993,154)
Net deferred tax assets not recognised	**241,755,871**	**86,172,976**
Movements		
Opening balance at 1 July	6,993,154	8,269,654
(Charged) / Credited to the income statement	3,727,187	(1,276,500)
Closing balance at 30 June	10,720,341	6,993,154
Deferred tax assets to be recovered after more than 12-months	9,531,395	6,970,577
Deferred tax assets to be recovered within 12-months	1,188,946	22,577
	10,720,341	6,993,154
Deferred tax liabilities		
Acquired income	16,177	1,581
Capitalised exploration	437,254	844,254
Property, plant and equipment	8,643,680	3,963,768
PRRT	1,623,230	2,183,551
Total deferred tax assets before set-offs	10,720,341	6,993,154
Set-off of deferred tax liabilities pursuant to set-off provisions	(10,720,341)	(6,993,154)
Net deferred tax liabilities	—	—
Movements		
Opening balance at 1 July	6,993,154	8,269,654
Charged / (Credited) to the income statement	3,727,187	(1,276,500)
Closing balance at 30 June	10,720,341	6,993,154
Deferred tax liabilities to be recovered after more than 12-months	10,704,164	6,991,573
Deferred tax liabilities to be recovered within 12-months	16,177	1,581
	10,720,341	6,993,154

5. REMUNERATION OF AUDITORS

	2016 $	2015 $
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	170,330	160,733
Southern Georgina joint arrangement audit	—	3,060
	170,330	163,793
(ii) Taxation services		
Income Tax compliance	17,628	8,500
Excise consulting services	4,500	48,957
Other tax related services	19,019	68,354
	41,147	125,811
(iii) Other services		
Magellan transaction due diligence	—	22,000
Mereenie transaction due diligence	90,999	—
Technical accounting advice on major transactions	27,181	—
Employee related services	—	6,698
	118,180	28,698
Total remuneration of PwC	**329,657**	318,302

6. CASH AND CASH EQUIVALENT

Cash at bank and in hand	15,115,699	3,516,139
Made up as follows:		
Corporate (a)	14,439,416	3,254,312
Joint arrangements (b)	676,283	261,827
	15,115,699	3,516,139

(a) $4,981,343 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2015: $1,046,123), 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 34. 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

	NOTE	2016 $	2015 $
Current			
Trade receivables		471,752	244,657
Accrued income (a)		2,524,009	858,001
Accrued research and development refund		—	4,072,557
Other receivables		25,883	14,540
GST receivables		—	38,740
Prepayments		765,634	640,837
		3,787,278	**5,869,332**

(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 34.

8. INVENTORIES

Crude oil and natural gas		238,947	137,877
Spare parts and consumables		2,592,508	850,064
Drilling materials and supplies at cost		761,106	1,148,732
		3,592,561	**2,136,673**

9. ASSETS HELD FOR SALE

Land and buildings		—	355,736
Exploration assets	11	—	1,400,000
		—	**1,755,736**

During the 2015 year, the Consolidated Entity decided to sell a residential property in Alice Springs which was previously used as employee accommodation. The property was subsequently sold in August 2015. The asset was not allocated to an operating segment in Note 24.

In 2015 the Consolidated Entity also made the decision to divest of its interests in a number of exploration permits and was negotiating with interested parties. These assets were allocated to the Exploration segment in Note 24.

Non-recurring fair value measurements

Real property and exploration permits held for sale during the prior period were measured at the lower of their carrying values and their fair values less cost to sell at the time of the reclassification. Both items were valued using indicative offers being considered or being negotiated for the disposal of the assets.

As a result of this impairment, losses of $67,072 were recognised in the 2015 year in respect of the residential property still held for sale at 30 June 2015, and impairment losses of $5,615,460 were recognised in the 2015 year in respect of the exploration permits held for sale.

Subsequent unsuccessful negotiations in respect of the exploration permits resulted in these assets being fully impaired during the current year.

10. PROPERTY, PLANT AND EQUIPMENT

	FREEHOLD LAND AND BUILDINGS $	PRODUCING ASSETS $	ASSETS IN DEVELOPMENT $	PLANT AND EQUIPMENT $	RESTORATION ASSET $	TOTAL $
Year ended 30 June 2015						
Opening net book amount	417,403	18,299,802	18,419,290	4,407,685	4,721,972	46,266,152
Additions	260,924	—	2,249,802	17,864,528	470,154	20,845,408
Assets classified as held for sale	(315,738)	—	—	—	—	(315,738)
Transfers / reclassifications	—	13,936,901	(20,669,092)	6,732,191	—	—
Disposals and write offs	—	—	—	—	—	—
Impairment	(100,821)	(381,089)	—	(4,346,903)	(692,302)	(5,521,115)
Depreciation charge	(844)	(1,047,939)	—	(1,344,347)	(304,162)	(2,697,292)
Closing net book amount	**260,924**	**30,807,675**	—	**23,313,154**	**4,195,662**	**58,577,415**
At 30 June 2015						
Cost	260,924	32,750,137	—	30,725,815	5,261,271	68,998,147
Accumulated depreciation	—	(1,942,462)	—	(7,412,661)	(1,065,609)	(10,420,732)
Net book amount	**260,924**	**30,807,675**	—	**23,313,154**	**4,195,662**	**58,577,415**
Year ended 30 June 2016						
Opening net book amount	260,924	30,807,675	—	23,313,154	4,195,662	58,577,415
Additions	—	—	—	1,411,501	1,450,511	2,862,012
Mereenie assets acquisition	3,558,479	34,003,686	—	12,112,947	11,084,270	60,759,382
Disposals and write offs	—	—	—	(69)	—	(69)
Impairment	—	—	—	(31,384)	—	(31,384)
Depreciation charge	(290,229)	(2,070,567)	—	(5,440,566)	(582,740)	(8,384,102)
Closing net book amount	**3,529,174**	**62,740,794**	—	**31,365,583**	**16,147,703**	**113,783,254**
At 30 June 2016						
Cost	3,819,403	66,872,949	—	44,130,961	17,796,052	132,619,365
Accumulated depreciation	(290,229)	(4,132,155)	—	(12,765,378)	(1,648,349)	(18,836,111)
Net book amount	**3,529,174**	**62,740,794**	—	**31,365,583**	**16,147,703**	**113,783,254**

11. EXPLORATION ASSETS

	NOTE	**2016 $**	2015 $
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	16,869,693
Impairment of exploration assets		—	(6,570,926)
Permits reclassified as held for sale	9	—	(1,400,000)
Balance at the end of the year		**8,898,767**	**8,898,767**

12. INTANGIBLE ASSETS

	2016 $	2015 $
SOFTWARE		
At the beginning of the year		
Cost	262,311	274,644
Accumulated amortisation	(250,259)	(255,123)
Net book value	**12,052**	**19,521**
Movements for the year		
Opening net book amount	12,052	19,521
Additions	96,053	2,828
Impairment	(5,661)	—
Amortisation	(20,051)	(10,297)
Closing net book amount	**82,393**	**12,052**
At the end of the year		
Cost	358,365	262,311
Accumulated amortisation	(275,972)	(250,259)
Net book value	**82,393**	**12,052**

13. OTHER FINANCIAL ASSETS

Security bonds on exploration permits and rental properties	**2,208,624**	**2,075,733**

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.

14. 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:

2016	Producing Assets
Sales volumes	Contracted
Sales price (% annual growth rate)	2.50%
Operating costs (% annual growth rate)	2.50%
Pre-tax discount rate (%)	13.31%

14. 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.

15. TRADE AND OTHER PAYABLES

	2016 $	2015 $
Current		
Trade payables	2,882,715	2,540,490
Other payables	234,650	558,410
Mereenie acquisition amounts due	3,358,590	—
Southern Georgina joint arrangement contribution	—	3,676,864
Accruals	420,434	932,133
	6,896,389	**7,707,897**
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 34.

16. DEFERRED REVENUE

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

	2016 $	2015 $
Current		
Available to be taken within 12-months	2,714,334	—
	2,714,334	—
Non-Current		
Available to be taken after 12-months	1,253,074	—
	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.

17. INTEREST BEARING LIABILITIES

		2016 $	2015 $
(a)	Interest bearing liabilities (current)[1]		
	Debt facilities	3,784,194	7,921,129
		3,784,194	**7,921,129**
(b)	Interest bearing liabilities (non-current)[1]		
	Debt facilities	81,916,860	39,536,722
		81,916,860	**39,536,722**

1 Details regarding interest bearing liabilities are contained in Note 34(e).

18. PROVISIONS

	2016			2015		
	Current $	Non-current $	Total $	Current $	Non-current $	Total $
Employee entitlements (a)	2,466,246	394,148	2,860,394	1,761,378	228,987	1,990,365
Onerous contracts (b)	199,076	82,400	281,476	298,952	392,939	691,891
Restoration and rehabilitation (c)	357,510	19,662,159	20,019,669	—	5,753,613	5,753,613
Joint Venture production over-lift (d)	743,881	—	743,881	—	—	—
Other	—	—	—	—	—	—
	3,766,713	**20,138,707**	**23,905,420**	**2,060,330**	**6,375,539**	**8,435,869**

(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:

	2016 $	2015 $
Current leave obligations expected to be settled after 12-months	662,419	520,916

(b) The provision for onerous contracts relates to operating lease commitments on the rental of office space at 167 Eagle Street, Brisbane.

(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 Consolidated Entity 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.

18. PROVISIONS (CONTINUED)

Movements in Provisions

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

2016	Employee Entitlements $	Onerous Contracts $	Restoration & Rehabilitation $	Other $	Total $
Carrying amount at start of year	**1,990,365**	**691,891**	**5,753,613**	**—**	**8,435,869**
Additional provision charged to property, plant and equipment	—	—	1,450,511	—	1,450,511
Provisions recognised upon acquisitions of interest in Mereenie Joint Venture	746,555	—	11,084,270	—	11,830,825
Additional provisions charged to profit or loss	1,371,590	—	1,337,970	743,881	3,453,441
Reversal of previous provisions		(218,764)	—	—	(218,764)
Unwinding of discount	—	—	393,305	—	393,305
Amounts used during the year	(1,248,116)	(191,651)	—	—	(1,439,767)
Carrying amount at end of year	**2,860,394**	**281,476**	**20,019,669**	**743,881**	**23,905,420**

19. OTHER FINANCIAL LIABILITIES

	2016 $	2015 $
Liabilities associated with forward gas sales agreements containing a cash settlement option		
Non-Current		
Available to be taken after 12-months	11,765,271	—
	11,765,271	**—**

20. CONTRIBUTED EQUITY

(a) Share capital

	2016 $	2015 $
433,197,647 (2015: 368,718,957) fully paid ordinary shares	172,301,532	160,785,182

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

	2016 No. of shares	2015 No. of shares	2016 $	2015 $
Balance at start of year	368,718,957	348,718,957	160,785,182	155,223,040
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	—
Placement of shares to institutional investors on 2 October 2014 at 30 cents per share	—	20,000,000	—	6,000,000
Capital raising costs	—	—	(734,640)	(437,858)
	433,197,647	**368,718,957**	**172,301,532**	**160,785,182**

20. 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
01 September 2015	Unlisted options issued to Macquarie Bank Limited[1]	01 Sep 2019	20 cents	30,000,000

[1] *Options issued as part consideration for the financing facility provided in connection with the Mereenie acquisition. Refer also to previous options cancelled below.*

(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	31 Oct 2015	$0.550	120,000
Unlisted employee options	15 Nov 2015	$0.400	220,000
Unlisted director options	15 Nov 2015	$0.450	11,050,304
Unlisted employee options	15 Nov 2015	$0.450	4,354,334
Unlisted employee options	15 Nov 2015	$0.650	207,000
Unlisted employee options	12 May 2016	$0.600	40,000

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

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted options held by Macquarie Bank Limited[1]	31 Oct 2015	$0.550	15,000,000

[1] *Cancellation of unlisted options previously issued to Macquarie Bank Limited as consideration for the financing facility provided in connection with the acquisition from Magellan Petroleum Australia.*

(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 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 2017	$0.475	2,318,668
Unlisted employee options	15 Nov 2017	$0.475	400,000
Unlisted consulting options	15 Nov 2017	$0.450	24,900,772
Unlisted director options	15 Nov 2017	$0.450	2,733,335
Unlisted employee options	15 Nov 2017	$0.475	2,799,350
Unlisted employee options	15 Nov 2017	$0.400	782,525
Unlisted employee options	15 Nov 2017	$0.410	234,000
Unlisted employee options	15 Nov 2017	$0.450	2,429,068
Unlisted employee options	15 Nov 2017	$0.650	393,900

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

20. 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	2,138,541
Employee LTIP rights	05 Jan 2021	1 Jul 2014	191,031
Employee LTIP rights	05 Jan 2021	1 Jul 2015	5,878,848
Employee LTIP rights	09 Feb 2021	1 Jul 2015	1,913,873

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.

21. RESERVES

	2016 $	2015 $
Share options reserve	**19,590,431**	**16,695,379**
Movements:		
Balance at start of year	16,695,379	14,448,696
Share based payment costs (a)	2,235,544	2,246,683
Options issued for financing (b)	659,508	–
Balance at end of year	**19,590,431**	**16,695,379**

(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 33 for further details of share based payments.

(b) 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.

22. ACCUMULATED LOSSES

	2016 $	2015 $
Movements in accumulated losses were as follows:		
Balance at the start of year	(154,334,061)	(126,603,023)
Net loss for the year	(21,040,292)	(27,731,038)
Balance at end of year	**(175,374,353)**	**(154,334,061)**

23. LOSSES PER SHARE

		2016	2015
(a)	**Basic loss per share (cents)**	**(5.16)**	**(7.63)**
(b)	**Diluted loss per share (cents)**	**(5.16)**	**(7.63)**
(c)	**Loss used in loss per share calculation**		
	Loss attributed to ordinary equity holders of the Company	**(21,040,292)**	**(27,731,038)**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic and diluted earnings per share	**408,108,471**	**363,568,272**

Options 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 20(f) for details of options on issue.

24. 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.

24. SEGMENT REPORTING (CONTINUED)

	PRODUCING ASSETS 2016 $	DEVELOPMENT ASSETS 2016 $	EXPLORATION ASSETS 2016 $	CORPORATE ITEMS 2016 $	CONSOLIDATION 2016 $
Revenue (a)	23,862,569	—	—	—	23,862,569
Cost of sales (b)	(14,060,704)	—	—	—	(14,060,704)
Gross profit (c)	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 (d)	(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**

(a) Revenue from the Producing Assets segment for the year ended 30 June 2016 includes 10-months of revenues for the Mereenie oil and gas field, which was acquired on 1 September 2015. Also included in revenue were amounts totalling $1,220,000 received as stand-by fees under a short term arrangement with Power & Water Corporation (as presented separately in the Consolidated Statement of Profit or Loss and Other Comprehensive Income).

(b) The Dingo pipeline and gas processing facilities were installed ready to deliver under the PWC GSA from 1 April 2015, however, sales awaited the customer's physical tie-in to the Dingo delivery point and as such no gas was physically supplied from the Dingo field until December 2015. Interim gas was supplied under the contract from September 2015 from the Palm Valley field. The contract contains a "Take-or-Pay" arrangement, however, this is based on a calendar year and is not payable until January in the following year. No revenue has been recognised to 30 June 2016 in accordance with the accounting policy for revenue recognition (refer Note 1(e)(i)).

(c) Other operating costs comprise a one-off amount of $1.725 million in respect of restructuring future contingent production bonus payments from the Mereenie field, effectively eliminating the future contingent liability (refer Note 31(a)(iii)).

Finance costs totalling $7.33 million relate to the Macquarie debt facility for the acquisition of the Palm Valley, Dingo and Mereenie fields and comprise amortisation of borrowing costs of $1.15 million and loan interest of $6.18 million (refer Note 34(e) for details on the facility). The Macquarie facility is secured by the Palm Valley, Dingo and Mereenie oil and gas fields and is serviced by their respective cash flows.

24. SEGMENT REPORTING (CONTINUED)

	PRODUCING ASSETS 2015 $	DEVELOPMENT ASSETS 2015 $	EXPLORATION ASSETS 2015 $	CORPORATE ITEMS 2015 $	CONSOLIDATION 2015 $
Revenue	10,313,266	—	—	—	10,313,266
Cost of sales	(10,117,038)	—	—	—	(10,117,038)
Gross profit	196,228	—	—	—	196,228
Other income	—	—	—	7,480,298	7,480,298
Share based employee benefits	—	—	—	(2,246,683)	(2,246,683)
General and administrative expenses	—	—	—	(1,938,425)	(1,938,425)
Employee benefits and associated costs	—	—	—	(5,018,180)	(5,018,180)
EBITDAX	**196,228**	**—**	**—**	**(1,722,990)**	**(1,526,762)**
Depreciation and amortisation	(2,370,662)	—	(24,045)	(312,882)	(2,707,589)
Exploration expenditure	—	—	(7,655,931)	—	(7,655,931)
Finance costs	(3,731,885)	—	—	(16,829)	(3,748,714)
Impairment expense	(5,420,293)	—	(6,570,927)	(100,822)	(12,092,042)
Loss before income tax	**(11,326,612)**	**—**	**(14,250,903)**	**(2,153,523)**	**(27,731,038)**
Taxes	—	—	—	—	—
Loss for the year	**(11,326,612)**	—	**(14,250,903)**	**(2,153,523)**	**(27,731,038)**
Segment assets	**64,848,349**	—	**11,641,829**	**10,257,939**	**86,748,117**
Segment liabilities	**(54,412,442)**	—	**(4,880,467)**	**(4,308,708)**	**(63,601,617)**
Capital expenditure					
Property, plant and equipment	2,333,592	18,442,116	8,253	61,447	20,845,408
Total capital expenditure	**2,333,592**	**18,442,116**	**8,253**	**61,447**	**20,845,408**

In 2016, the Group changed its segment reporting to combine oil and gas producing assets into one segment, primarily as a result of the acquisition of a 50% interest in the Mereenie joint operation which comprises both oil and gas operations and has common expenditure across both streams. Consequently, the 2015 segment reporting note has been revised to reflect the same reporting format as 2016.

	2016 $	2015 $
Revenue from external customers by geographical location of production		
Australia	23,862,569	10,313,266
Non-current assets by geographical location		
Australia	128,627,177	73,470,237

Major Customers

Revenue from one customer represents $8,113,631 or 36% of the Group's total oil and gas revenues (2015: $8,223,782 or 80 % of the Group's total oil and gas revenues). Revenue from a second customer represents $6,985,762 or 32% of the Group's total oil and gas revenues (2015: Nil). Revenue from a third customer represents $5,000,264 or 22% of the Group's total oil and gas revenues (2015: Nil).

No other customers had revenue exceeding 10% of the Group's total oil and gas revenue for the 2016 year.

25. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2016 $	2015 $
Statement of financial position		
Current assets	11,377,033	9,872,277
Non-current assets	8,864,537	9,065,573
Total assets	20,241,570	18,937,850
Current liabilities	(7,013,781)	(3,915,769)
Total liabilities	(7,096,181)	(4,308,708)
Net assets	13,145,389	14,629,142
Shareholders' equity		
Issued capital	172,301,532	160,785,182
Reserves	19,590,431	16,695,379
Accumulated losses	(178,746,574)	(162,851,419)
Total equity	13,145,389	14,629,142
Loss for the year	**(15,895,155)**	**(8,632,069)**
Total comprehensive loss	**(15,895,155)**	**(8,632,069)**

(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 31(a)(iii).

(d) Commitments of the Parent Entity

Operating lease commitments of the Parent Entity are set out in Note 32(b).

26. 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 2016 %	2015 %
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	—
Central Petroleum Mereenie Unit Trust	N/A	Units	100	—

(c) Key management personnel

Disclosures relating to key management personnel are set out in Note 27.

27. KEY MANAGEMENT PERSONNEL

(a) Key management personnel compensation

	2016 $	2015 $
Short-term employee benefits	2,812,486	3,090,130
Post-employment benefits	215,877	210,674
Termination benefits	116,923	—
Long-term benefits	38,867	50,439
Share based payments	1,902,000	2,150,273
	5,086,153	**5,501,516**

Detailed remuneration disclosures are provided in the remuneration report on pages 20 to 31.

(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 31.

27. 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	OTHER CHANGES	HELD AT DATE OF DEPARTURE	BALANCE AT END OF YEAR	VESTED EXERCISABLE	UNVESTED
Non-Executive Directors									
Andrew Whittle[1]	2016	900,000	—	—	—	900,000	N/A	N/A	N/A
	2015	900,000	—	—	—	N/A	900,000	300,000	600,000
Wrixon Gasteen	2016	1,000,000	—	—	(333,334)	N/A	666,666	—	666,666
	2015	1,000,000	—	—	—	N/A	1,000,000	333,334	666,666
Robert Hubbard	2016	—	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—	—
J Thomas Wilson	2016	—	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—	—
Peter Moore	2016	—	—	—	—	—	—	—	—
	2015	—	—	—	—	—	—	—	—
Executive Directors and Other Key Management Personnel									
Richard Cottee[2]	2016	34,584,407	—	—	(9,683,634)	N/A	24,900,773	—	24,900,773
	2015	34,584,407	—	—	—	N/A	34,584,407	9,683,634	24,900,773
Michael Herrington[3]	2016	2,250,000	—	—	(300,000)	N/A	1,950,000	—	1,950,000
	2015	2,700,000	—	—	(450,000)	N/A	2,250,000	300,000	1,950,000
Daniel White	2016	1,493,334	—	—	(733,334)	N/A	760,000	310,000	450,000
	2015	1,643,334	450,000	—	(600,000)	N/A	1,493,334	1,043,334	450,000
Bruce Elsholz[4]	2016	N/A	—	—	—	N/A	N/A	N/A	N/A
	2015	1,170,000	370,500	—	(400,000)	1,140,500	N/A	N/A	N/A
Leon Devaney	2016	1,064,000	—	—	(560,000)	N/A	504,000	—	504,000
	2015	560,000	504,000	—	—	N/A	1,064,000	560,000	504,000
Michael Bucknill[5]	2016	430,000		—	(100,000)	330,000	N/A	N/A	N/A
	2015	—	430,000	—	—	N/A	430,000	100,000	330,000
Robbert Willink	2016	450,000	—	—	(120,000)	N/A	330,000	—	330,000
	2015	—	450,000	—	—	N/A	450,000	120,000	330,000

[1] *Mr Whittle resigned as director 2 November 2015*

[2] *34,584,407 unlisted options exercisable at $0.45 on or before 15 November 2015 and 15 November 2017 were issued to FEP on 8 August 2012, a company in which Richard Cottee has a 50% beneficial interest.*

[3] *Mr Herrington retired as director effective 26 November 2014. Michael Herrington remains Chief Operating Officer.*

[4] *Mr Elsholz resigned effective 30 November 2014.*

[5] *Mr Bucknill ceased employment 26 February 2016*

(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.

27. 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	2016	—	2,104,904	—	N/A	—	2,104,904
	2015	—	—	—	N/A	—	—
Michael Herrington[1]	2016	—	930,000	—	N/A	—	930,000
	2015	—	—	—	N/A	—	—
Daniel White	2016	330,000	770,000	—	N/A	—	1,100,000
	2015	—	330,000	—	N/A	—	330,000
Leon Devaney	2016	278,571	783,000	—	N/A	—	1,061,571
	2015	—	278,571	—	N/A	—	278,571
Michael Bucknill[2]	2016	274,285	640,000	(914,285)	—	—	N/A
	2015	—	274,285	—	N/A	—	274,285
Robbert Willink	2016	262,286	—	—	N/A	—	262,286
	2015	—	262,286	—	N/A	—	262,286

[1] *Mr Herrington retired as director effective 26 November 2014. Michael Herrington remains Chief Operating Officer.*
[2] *Mr Bucknill ceased employment 26 February 2016*

(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								
Andrew Whittle[1]	2016	236,044	N/A	—	—	—	236,044	N/A
	2015	133,680	N/A	102,364	—	—	N/A	236,044
Wrixon Gasteen	2016	97,000	N/A	39,473	—	—	N/A	136,473
	2015	97,000	N/A	—	—	—	N/A	97,000
Robert Hubbard	2016	120,000	—	178,947	—	—	N/A	298,947
	2015	64,100	—	55,900	—	—	N/A	120,000
J Thomas Wilson	2016	—	—	—	—	—	N/A	—
	2015	—	—	—	—	—	N/A	—
Peter Moore	2016	—	—	—	—	—	N/A	—
	2015	—	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2016	436,383	N/A	196,055	—	—	N/A	632,438
	2015	208,683	N/A	227,700	—	—	N/A	436,383
Michael Herrington[2]	2016	250,000	N/A	—	—	—	N/A	250,000
	2015	200,000	N/A	50,000	—	—	N/A	250,000
Daniel White	2016	288,000	N/A	—	—	—	N/A	288,000
	2015	288,000	N/A	—	—	—	N/A	288,000
Leon Devaney	2016	210,000	N/A	—	—	—	N/A	210,000
	2015	110,000	N/A	100,000	—	—	N/A	210,000
Michael Bucknill[3]	2016	56,000	N/A		—	—	56,000	N/A
	2015	31,000	N/A	25,000	—	—	N/A	56,000
Robbert Willink	2016	—	N/A	—	—	—	N/A	—
	2015	—	N/A	—	—	—	N/A	—

[1] *Mr Whittle resigned as director 2 November 2015*
[2] *Mr Herrington retired as director effective 26 November 2014*
[3] *Mr Bucknill ceased employment 26 February 2016*

27. KEY MANAGEMENT PERSONNEL (CONTINUED)

(c) Other transactions with key management personnel

(i) Prior to 26 June 2015 Freestone Energy Partners Pty Ltd ("FEP") provided the services of Richard Cottee on the basis of a secondment to the Company.

During the year ended 30 June 2015 FEP received compensation of $518,783.

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

	2016 $	2015 $
Loss after income tax	(21,040,292)	(27,731,038)
Adjustments for:		
Depreciation and amortisation	8,404,153	2,707,589
Loss on disposal of assets	1,445	—
Share-based payments	2,235,544	2,246,683
Income tax expense	—	—
Impairment expense	1,437,045	12,092,042
Financing costs and interest (non-cash)	971,582	3,461,743
Changes in assets and liabilities relating to operating activities:		
(Increase) / Decrease in trade and other receivables	2,082,054	(2,920,023)
(Increase) / Decrease in inventories	47,307	(195,691)
Increase in trade and other payables	(771,751)	101,327
(Decrease) / Increase in deferred revenue	3,967,407	—
(Decrease) / Increase in provisions	1,794,910	(362,965)
Net Cash Outflow from Operations	**(870,596)**	**(10,600,333)**

29. NON CASH INVESTING AND FINANCING ACTIVITIES

There were no non-cash financing or investing activities during the year (2015: Nil).

30. MEREENIE ASSET ACQUISITION

On 1 September 2015, the Group completed the acquisition of a 50% interest in the Mereenie oil and gas assets from the Santos Group. The arrangement constitutes a joint arrangement under AASB 11. The total cost of acquisition, including transaction costs not previously expensed, has been allocated over the identifiable assets and liabilities on the basis of their relative fair values. Details of the assets and liabilities acquired are set out below:

	Assets and Liabilities recognised on acquisition $
Assets	
Inventory	1,503,195
Producing properties and permits	34,003,686
Property, plant and equipment (including Restoration assets)	26,755,696
	62,262,577
Liabilities	
Provisions for employee liabilities	746,555
Provision for restoration and rehabilitation	11,084,270
	11,830,825
Net assets acquired on completion	**50,431,752**
Consideration:	
Cash	35,000,000
Deferred consideration payable	10,000,000
Pre NEGI appraisal works — Santos free carry	5,000,000
Transaction costs	431,752
Total consideration	**50,431,752**

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, certain amounts are payable to Santos in the event that Central elects to enter into a Gas Transportation Agreement (“GTA”) with the NGP (Northern Gas Pipeline, formerly NEGI, the North East Gas Interconnect) project owner within three years of execution date. The Group, under these circumstances, would be required to make a $15 million lump sum payment to Santos and also sole fund the associated gas development project ($55 million - $75 million).

31. CONTINGENCIES

(a) Contingent liabilities

(i) The Consolidated Entity had contingent liabilities at 30 June 2016 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 (2015: $1,000,000) within 12-months following the commencement of any future commercial production from the permits.

(ii) 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 price hurdles are in excess of the current gas prices received from the Palm Valley gas field and escalate annually with CPI. 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 (or anticipated to be payable) at this time. Given 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 significantly higher priced markets eventuate, this contingent liability will be revisited. Importantly, any future payment of the Gas Price Bonus would likely only occur where sales and revenues from the Palm Valley gas field materially exceed our acquisition assumptions.

31. CONTINGENCIES (CONTINUED)

(iii) Under a Sale And Purchase Agreement between Santos QNT Pty Ltd ("Santos QNT") and Santos Limited and Magellan Petroleum (NT) Pty Ltd (now known as Central Petroleum (NT) Pty Ltd) ("CPNT") dated 15 September 2011, CPNT acquired the rights to a Bonus Amount (described below) which Bonus Amount was subsequently assigned to Magellan Petroleum Australia Pty Ltd ("MPA") under a Deed of Consent Bonus Amount between MPA, CPNT and Santos entities dated 26 March 2014.

Under the Sale and Purchase Agreement entered into with Santos QNT and other parties in June 2015 for the purchase of a 50% interest in the Mereenie Oil & Gas Field and related assets, Central Petroleum Mereenie Pty Ltd as trustee for The Central Petroleum Mereenie Unit Trust ("CPMUT") is obliged to indemnify Santos QNT in respect of 50% to the extent the Bonus Amount is payable by Santos QNT.

On 18 May 2016, Macquarie Bank Limited ("MBL") acquired the rights to the Bonus Amount previously held by MPA.

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.

The Bonus Amount may become payable to MBL if, at any time until 1 July 2031, the 90-Day Average Net Sales exceeds a Threshold Level determined in accordance with the table set out below:

Threshold Level *(90 Day Average Net Sales in BOE per day)*	**Gross Joint Venture Bonus Amount ($A million)** *(CTP indemnifies Santos QNT for 50% of this, whilst also becoming entitled to 50% from MBL)*
Less than 2,500	Nil
Greater than or equal to 2,500	5.00
Greater than or equal to 2,750	0.25
Greater than or equal to 3,000	0.25
Greater than or equal to 3,250	0.25
Greater than or equal to 3,500	0.25
Greater than or equal to 3,750	0.25
Greater than or equal to 4,000	0.25
Greater than or equal to 4,250	0.25
Greater than or equal to 4,500	0.25
Greater than or equal to 4,750	0.25
Greater than or equal to 5,000	0.25
Greater than or equal to 10,000	10.00

At financial year end the 90-Day Average Net Sales from Mereenie was approximately 1,940 boe which is below the thresholds above and therefore no Bonus Amount is payable. Given current uncontracted reserves at Mereenie, we may pay a Bonus Amount at some time in the future and ascribe a $1.725 million value to this contingent liability. This contingent liability will be revisited periodically as production forecast evolve. Importantly any future payment of a Bonus Amount would likely only occur where sales and revenues from Mereenie materially exceed the Bonus Amount which may be payable. Refer also Contingent Asset note below.

(iv) Central Petroleum Limited has allegedly been served with litigation field in the District Court of Harris County, located in Houston, Texas, in respect of a farm-in deal negotiated between the Perth office of Total and Central Petroleum Limited when it was headquartered in Perth. Central Petroleum is disputing the Court's jurisdiction. Separately, internal investigations have concluded that there is no factual basis for the alleged claim and the Company denies any liability. The action will be vigorously defended.

(v) 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, certain amounts are payable to Santos in the event that Central elects to enter into a Gas Transportation Agreement ("GTA") with the NGP (Northern Gas Pipeline, formerly NEGI, the North East Gas Interconnect) project owner within 3-years of execution date. The Group, under these circumstances, would be required to make a $15 million lump sum payment to Santos and also sole fund the associated gas development project ($55 million - $75 million).

(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. This effectively offsets the Consolidated Entity's obligations to indemnify Santos for the 50% of any Bonus payable.

32. COMMITMENTS

(a) Capital commitments

The Consolidated Entity has the following exploration expenditure commitments:

	2016 $	2015 $
The following amounts are due:		
Within one year	10,750,000	5,516,898
Later than one year but not later than three years	4,160,000	15,500,000
Later than three years but not later than five years	12,750,000	8,000,000
	27,660,000	**29,016,898**

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 them altogether 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:

	2016 $	2015 $
Within one year	743,676	757,316
Later than one year but not later than five years	947,465	1,483,533
	1,691,141	**2,240,849**

33. 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.

33. SHARE BASED PAYMENTS (CONTINUED)

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

EXPIRY DATE	EXERCISE PRICE[1]	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	

[1] *On 27 September 2013 shareholders approved every 5 ordinary shares held be converted into 1 ordinary share (subject to rounding).*

33. SHARE BASED PAYMENTS (CONTINUED)

EXPIRY DATE	EXERCISE PRICE[1]	BALANCE AT START OF THE YEAR No.	GRANTED DURING THE YEAR No.	EXERCISED DURING THE YEAR No.	EXPIRED OR FORFEITED DURING THE YEAR No.	BALANCE AT END OF THE YEAR No.	VESTED AND EXERCISABLE AT THE END OF THE YEAR $
2015							
31 May 2015	$0.610	1,268,000	—	—	(1,268,000)	—	—
31 Oct 2015	$0.550	120,000	—	—	—	120,000	120,000
15 Nov 2015	$0.400	—	220,000	—	—	220,000	220,000
15 Nov 2015	$0.450	9,683,634	—	—	—	9,683,634	9,683,634
15 Nov 2015	$0.450	4,354,334	—	—	—	4,354,334	4,354,334
15 Nov 2015	$0.450	1,366,670	—	—	—	1,366,670	1,366,670
15 Nov 2015	$0.650	207,000	—	—	—	207,000	207,000
12 May 2016	$0.600	40,000	—	—	—	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	1,800,000	1,449,350	—	(450,000)	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		**50,861,748**	**5,508,843**	—	**(1,718,000)**	**54,652,591**	**20,379,640**
Weighted average exercise price		$0.46	$0.44	—	$0.57	$0.46	$0.46
Weighted average remaining contractual life (years) at the end of the year						1.71	

(b) Employee options granted during the year

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

The following options were granted during the year ended 30 June 2015:

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
2015								
17 Jul 2014	15 Nov 2015	220,000	$0.020	$0.400	$0.375	45% to 65%	2.79%	0.0%
9 Apr 2015	15 Nov 2017	1,449,350	$0.059	$0.475	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	2,429,068	$0.062	$0.450	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	782,525	$0.067	$0.400	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	234,000	$0.066	$0.410	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	393,900	$0.043	$0.650	$0.125	55% to 75%	1.74%	0.0%

* *The estimated price volatility is based on the historical price volatility for the 12-months prior to the date of granting of the options, adjusted for any expected changes to future volatility due to publicly available information.*

33. SHARE BASED PAYMENTS (CONTINUED)

(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 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. 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
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	—	6,042,628	$0.147	—	(698,262)	5,344,366
22 Dec 2015	30 June 2015	—	191,031	$0.085	—	—	191,031
17 Jun 2015	30 June 2015	2,811,401	—	$0.074	—	(274,285)	2,537,116
Totals		**2,811,401**	**8,682,010**		—	**(972,547)**	**10,520,864**
2015							
17 Jun 2015	30 June 2015	—	2,811,401	$0.074	—	—	2,811,401

(d) Expenses arising from share-based payment transactions

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

	2016 $	2015 $
Options and rights issued to directors and employees	2,235,544	2,246,683

34. 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.

34. FINANCIAL RISK MANAGEMENT (CONTINUED)

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

TRADE AND OTHER RECEIVABLES	GROSS 2016 $	GROSS 2015 $	IMPAIRMENT 2016 $	IMPAIRMENT 2015 $
Past due: 0-30 days	3,021,644	4,746,959	—	—
Past due: 31-150 days	—	481,536	—	—
Past due: 151-365 days	—	—	—	—
	3,021,644	**5,228,495**	—	—

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 2016 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 25(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:

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)**

2015	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	3,516,139	—	—	—	3,516,139
Trade and other receivables	5,228,495	—	—	—	5,228,495
Other financial assets	—	—	2,075,733	—	2,075,733
	8,744,634	—	**2,075,733**	—	**10,820,367**
Financial Liabilities					
Trade and other payables	(7,707,897)	—	—	—	(7,707,897)
Interest bearing liabilities	(1,345,761)	(6,575,368)	(39,536,722)	—	(47,457,851)
	(9,053,658)	**(6,575,368)**	**(39,536,722)**	—	**(55,165,748)**

34. FINANCIAL RISK MANAGEMENT (CONTINUED)

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

The Group had access to the following undrawn borrowing facilities at the end of the reporting period:

	NOTE	**2016**	2015
		$	$
Macquarie debt facility (floating rate)	34(e)	—	2,692,152

(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	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
	%	%	**$**	$	**$**	$	**$**	$	**$**	$
Financial Assets:										
Cash and cash equivalents	1.5	1.2	15,115,699	3,516,139	—	—	—	—	15,115,699	3,516,139
Trade and other receivables	—	—	—	—	—	—	3,021,644	5,228,495	3,021,644	5,228,495
Other financial assets	1.2	0.7	—	—	920,982	858,391	1,287,642	1,217,342	2,208,624	2,075,733
			15,115,699	**3,516,139**	**920,982**	**858,391**	**4,309,286**	**6,445,837**	**20,345,967**	**10,820,367**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(6,896,389)	(7,707,897)	(6,896,389)	(7,707,897)
Interest bearing liabilities	7.7	10.4	(85,431,135)	(47,457,851)	(269,919)	—	—	—	(85,701,054)	(47,457,851)
Other financial liabilities	—	—	—	—	—	—	(11,765,271)	—	(11,765,271)	—
			(85,431,135)	**(47,457,851)**	**(269,919)**	—	**(18,661,660)**	**(7,707,897)**	**(104,362,714)**	**(55,165,748)**
Net Financial Assets / (Liabilities)			**(70,315,436)**	**(43,941,712)**	**651,063**	**858,391**	**(14,352,374)**	**(1,262,060)**	**(84,016,747)**	**(44,345,381)**

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 2015.

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2016				
Cash and cash equivalents	10,371	(10,371)	—	—
Interest bearing liabilities	656,002	(656,002)	—	—
2015				
Cash and cash equivalents	4,900	(4,900)	—	—
Interest bearing liabilities	492,186	(492,186)	—	—

34. FINANCIAL RISK MANAGEMENT (CONTINUED)

(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.

(e) Financing Facilities

The Group has a Loan Facility Agreement ("Facility") with Macquarie Bank Limited ("Macquarie"). The previous Facility was expanded to fund the Mereenie acquisition from Santos in September 2015 and consists of four tranches totalling $90 million. $89.8 million of the available Facility was drawn down.

Interest costs are based on fixed spreads over the periodic Bank Bill Swap ("BBSW") average bid rate. The Facility terms were amended such that from the Utilisation Date under the new Facility D the interest rate spread stepped down. The expanded 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.

35. INTEREST IN JOINT ARRANGEMENTS

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

	PRINCIPAL ACTIVITIES	**2016** %	2015 %
OL4, OL5 and PL2 (Mereenie) (Santos)	Oil & gas exploration	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)	Oil & gas exploration	60.00	60.00
ATP 909 (Total)	Oil & gas exploration	90.00	90.00
ATP 911 (Total)	Oil & gas exploration	90.00	90.00
ATP 912 (Total)	Oil & gas exploration	90.00	90.00

Total = TOTAL GLNG Australia
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' and Total's 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.

35. 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:

	2016 $	2015 $
Current assets		
Cash and cash equivalents	676,283	12,330
Trade and other receivables	3,030,340	13,471
Inventory	1,667,137	387,625
Total current assets	5,373,760	413,426
Non-current assets		
Property, plant and equipment	57,251,808	161,108
Other financial assets	182,200	7,200
Total non-current assets	57,434,008	168,308
Current liabilities		
Trade and other payables	4,251,428	308,743
Accruals	513,980	109,423
Joint Venture under contributions*	—	3,676,864
Deferred revenue	730,878	—
Provision for production over-lift	743,881	—
Total current liabilities	6,240,167	4,095,030
Non-current liabilities		
Deferred revenue	439,497	—
Joint Venture under contributions*	2,069,220	—
Restoration provision	12,166,972	194,829
Total non-current liabilities	14,675,689	194,829
Net assets / (liabilities)	**41,891,912**	**(3,708,125)**
Joint arrangement contribution to loss before tax		
Revenue	17,255,241	9,986
Expenses	(20,817,628)	(6,257,000)
Profit / (Loss) before income tax	**(3,562,387)**	**(6,247,014)**

** The Group is liable for the last 20% of the Stage 1 expenditure in the Southern Georgina Joint Venture, with Total funding the first 80%.*

36. EVENTS OCCURRING AFTER THE REPORTING PERIOD

No matter or circumstance has arisen subsequent to 30 June 2016 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 35 to 80 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 2016 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 2016.

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

Richard Cottee
Managing Director
Brisbane

21 September 2016

Independent auditor's report to the members of Central Petroleum Limited

Report on the financial report

We have audited the accompanying financial report of Central Petroleum Limited (the Group), which comprises the consolidated statement of financial position as at 30 June 2016, the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year ended on that date, a summary of significant accounting policies, other explanatory notes and the directors' declaration for Central Petroleum Limited (the consolidated entity). The consolidated entity comprises the company and the entities it controlled at year's end or from time to time during the financial year.

Directors' responsibility 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 is free from material misstatement, whether due to fraud or error. In Note 1, the directors also state, in accordance with Accounting Standard AASB 101 *Presentation of Financial Statements*, that the financial statements comply with International Financial Reporting Standards.

Auditor's responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the consolidated entity's preparation and fair presentation of the financial report in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the directors, as well as evaluating the overall presentation of the financial report.

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

Independence

In conducting our audit, we have complied with the independence requirements of the *Corporations Act 2001*.

PricewaterhouseCoopers, ABN 52 780 433 757
480 Queen Street, BRISBANE QLD 4000, GPO Box 150, BRISBANE QLD 4001
T: +61 7 3257 5000, F: +61 7 3257 5999, www.pwc.com.au

pwc

Auditor's opinion

In our opinion:

(a) the financial report of Central Petroleum Limited is in accordance with the *Corporations Act 2001,* including:

(i) giving a true and fair view of the consolidated entity's financial position as at 30 June 2016 and of its performance for the year ended on that date; and

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

(b) the financial report and notes also comply with International Financial Reporting Standards as disclosed in Note 1.

Report on the Remuneration Report

We have audited the remuneration report included in pages 20 to 31 of the directors' report for the year ended 30 June 2016. 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.

Auditor's opinion

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2016 complies with section 300A of the *Corporations Act 2001*.

PricewaterhouseCoopers

PricewaterhouseCoopers

Michael Shewan
Partner

Brisbane
21 September 2016

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 15 SEPTEMBER 2016

Top holders

The 20 largest registered holders of the quoted securities as at 15 September 2016 were:

	NAME	NO. OF SHARES	%
1.	Citicorp Nominees Pty Limited	20,521,053	4.74
2.	Macquarie Bank Limited <Metals Mining and Ag A/C>	10,000,000	2.31
3.	Magellan Petroleum Australia Pty Ltd	8,247,576	1.90
4.	National Nominees Limited <DB A/C>	6,052,632	1.40
5.	J P Morgan Nominees Australia Limited	5,013,839	1.16
6.	Willowdale Holdings Pty Ltd	4,100,000	0.95
7.	UBS Nominees Pty Ltd	3,982,457	0.92
8.	Mr Mark Philip Shawcross	3,000,000	0.69
9.	Mr William Trickett Wright + Mrs Helen Elizabeth Wright <Just Wright Super Fund A/C>	3,000,000	0.69
10.	Mr Gerard Pieter Tom Van Brugge	2,860,000	0.66
11.	Edwin Holdings Pty Ltd	2,800,000	0.65
12.	HSBC Custody Nominees Australia Limited	2,651,199	0.61
13.	Lujeta Pty Ltd <The Margaret Account>	2,642,687	0.61
14.	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce and Joan Cochrane A/C>	2,578,947	0.60
15.	Franze Holdings Pty Ltd	2,046,546	0.47
16.	Mr Stuart Francis Howes	2,000,001	0.46
17.	BNP Parabis Noms Pty Ltd <DRP>	1,946,983	0.45
18.	Mr John Cresswell Leigh + Mrs Dulcie Lynette Leigh <JAD Super Fund No 2 A/C>	1,746,500	0.40
19.	Mr Geoffrey Rol	1,736,075	0.40
20.	Fanchel Pty Ltd	1,666,000	0.38
		88,592,495	20.45

DISTRIBUTION SCHEDULE

The distribution schedule of the ordinary fully paid shares as at 15 September 2016 was:

RANGE	HOLDERS	UNITS	%
1 - 1,000	888	452,494	0.10
1,001 -5,000	2,511	6,990,293	1.61
5,001 - 10,000	1,347	10,746,708	2.48
10,001 - 100,000	3,154	114,537,951	26.44
100,001 - Over	754	300,470,201	69.36
Total	8,654	433,197,647	100.00

GEOGRAPHIC BREAKDOWN

The geographic distribution schedule of the ordinary fully paid shares as at 15 September 2016 was:

LOCATION	HOLDERS	UNITS	%
Australia	8,592	355,073,889	96.30
Overseas	257	13,645,068	3.70
Total	8,849	368,718,957	100.00

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

There were no substantial shareholders with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity.

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 1,493 shares as at 15 September 2016):

HOLDERS	UNITS
3,157	6,243,895

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

			CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
TENEMENT	LOCATION	OPERATOR	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	0	100		
EP 93	Pedirka Basin NT	Central	100	100		
EP 97[2]	Pedirka Basin NT	Central	100	100		
EP 105[1]	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106[1]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 107	Amadeus/Pedirka Basin NT	Central	100	100		
EP 112[1]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 115 (excl. EP 115NMB)	Amadeus Basin NT	Central	100	100		
EP 115NMB (North Mereenie Block)	Amadeus Basin NT	Santos	60	60	Santos	40
EP 125	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	100	100		
OL 4 (Mereenie)	Amadeus Basin NT	Central	50	50	Santos	50
OL 5 (Mereenie)	Amadeus Basin NT	Central	50	50	Santos	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[1]	Georgina Basin QLD	Central	90	90	Total	10
ATP 911[1]	Georgina Basin QLD	Central	90	90	Total	10
ATP 912[1]	Georgina Basin QLD	Central	90	90	Total	10

PERMITS AND LICENCES UNDER APPLICATION

			CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
TENEMENT	LOCATION	OPERATOR	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111[3]	Amadeus Basin NT	Central	100	100		
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124[3]	Amadeus Basin NT	Central	100	100		
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		

PIPELINE LICENCES

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

[1] *Santos' and Total's 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.*

[3] *Central has granted Santos the right to acquire a 50% interest in EPA 111 and EPA 124.*