Interim Financial Report

Half-year ended 31 December

2018

Central Petroleum Limited
ABN 72 083 254 308

CONTENTS

Forward-looking statements

The Directors' Report contains forward-looking statements, including statements of current intention, statements of opinion and expectations regarding Central Petroleum Limited's ("**Central Petroleum**") present and future operations, possible future events and future financial prospects. Such statements are not statements of fact and may be affected by a variety of known and unknown risks, uncertainties, variables and changes in underlying assumptions or strategy that could cause Central Petroleum's actual results or performance to differ materially from the results or performance expressed or implied by such statements. There can be no certainty of outcome in relation to the matters to which the statements relate, and the outcomes are not all within the control of Central Petroleum. Some matters are subject to approval of joint venture participants and governmental authorities.

Central Petroleum makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward looking statement or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in the Directors' Report reflect expectations held at the date of that report. Except as required by applicable law or the Australian Securities Exchange (ASX) Listing Rules, Central Petroleum disclaims any obligation or undertaking to publicly update any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or of future events.

CHAIRMAN'S LETTER

Dear Fellow Shareholder,

31 December 2018 will be seen, in future years, as the point around which Central Petroleum pivoted from being a minor gas seller talking up the future to a company with significant sales revenue from its producing assets, as well as a large range of opportunities for further growth.

For shareholders who have been on the journey, it may seem as though little occurred, as one shareholder remarked to me. In fact, much has been achieved.

Prior to that pivot date, Central had some gas sales, but not much. It had a huge programme of work to upgrade its plants for increased production and there was always a concern that the Jemena Northern Gas Pipeline (NGP) would be delayed.

Now, the construction risks for Central and Jemena are largely eliminated by completion and start of operations and the company has much larger volumes of gas sold under firm Gas Sales Agreements (GSA).

To get to that pivot point was quite a journey.

The purchase of Palm Valley and Dingo about 5 years ago brought some income as did the purchase of the half interest in Mereenie in September 2015. Only three years ago, the company could sell gas to very few and was competing against a governmental agency. That it succeeded in gaining sales was remarkable. Even more remarkable was that the lobbying by Central and others for a connection to the East Coast markets was successful.

With the NGP under construction, the company negotiated a significant GSA with Incitec Pivot (IPL) which assured cash flow to undertake the necessary upgrades to be able to sell considerably more gas than previously.

The relationship with IPL also allowed Central and IPL to acquire acreage in Queensland where Central will drill wells this year to seek to find further gas closer to the East coast markets. IPL is funding this work, as previously announced.

The company results in the Interim Report show the beginnings of this pivot with the sales of commissioning gas to Jemena seen in the increase in sales. The further increase in January, as gas started to flow under the IPL GSA, can be seen in the company's presentation released to the ASX on 13 February 2019. The presentation can also be viewed on Central Petroleum's website.

As mentioned at the AGM and apparent in the quarterly report, most of the funds from these sales above normal business expenses is to be applied to scheduled debt reduction which the company took on to complete the work. Your Board took the view that borrowing to fund the projects was a better course than raising funds by issuing shares when the company's share price was well below the price your Board considered reflected fair value. Management are progressing the necessary work to refinance the debt, now that Central has moved to a more stable income stream.

A number of shareholders have expressed to me their frustration that, despite all this positive news, the share price remains stubbornly locked in its current range. Your Board shares that frustration, as do management, whose long-term incentives depend on improvement in the share price.

A number of theories have been advanced for this, but ultimately it requires the market to recognise just how transformational the pivot has been. One exciting near-term catalyst for share price appreciation is exploration drilling by Santos at the Dukas prospect. This is potentially a massive target, but (as with all exploration) one cannot be assured of success. If it is successful, one would expect a re-rating of the shares in Central.

In relation to the replacement of those who have left Central since 30 June, your Board is currently undertaking a search for additional directors with the requisite skills to undertake the board's work. We have been fortunate in securing the services of Kathy Hirschfeld and Stuart Baker who are outstanding folk from their respective disciplines. The search for further directors continues as we aim to have six directors to carry the load of what will be a very busy company.

As advised at the AGM, with respect to the CEO role, your Board expects to conclude this in the first quarter of this year.

We are also recruiting executives in other fields, principally exploration.

Chairman's Letter *(continued)*

Like all gas and oil fields, Central's current fields need constant management to continue to produce gas or oil. Management's focus is on maximising sales and optimising plant performance to capture Northern Territory and east coast gas sales opportunities.

We are also well placed to apply for acreage being released by the Queensland Government. As a new entrant in that State, without ties to the LNG plants and with operating and drilling experience, as well as CSG knowledge, Central scores well in the Government's assessment methodology.

The future for Central is very bright.

Yours faithfully

Martin Kriewaldt
Chairman
20 February 2019

DIRECTORS' REPORT

31 December 2018

The Directors present their report on the consolidated entity consisting of Central Petroleum Limited and the entities it controlled at the end of, or during, the half-year ended 31 December 2018.

Directors

The names of the Directors of the parent company in office during the half-year and until the date of this report are:

Martin D Kriewaldt – Chairman
Wrixon F Gasteen
Richard I Cottee (resigned 5 February 2019)
Leon G Devaney (appointed 14 November 2018)
Stuart T Baker (appointed 7 December 2018)
Katherine A Hirschfeld (appointed 7 December 2018)
Peter S Moore (resigned 13 November 2018)
Sarah Ryan (resigned 13 November 2018)
Timothy R Woodall (resigned 29 September 2018)

Directors have held office for the period and until the date of this report unless otherwise stated.

Review of Operations

The principal continuing activity of the consolidated entity ("the Group") during the period was the exploration, development and production of hydrocarbons.

Highlights for the half-year reporting period and up to the date of this report

- Operating revenue increased by 13.3% over the previous corresponding period from $17.7 million to $20.0 million.
- Gas sales volumes increased 14.8% over the previous corresponding period, reflecting gas sold under a short term Gas Supply Agreement ("GSA") with Jemena, the owner of the Northern Gas Pipeline ("NGP") which commenced in late October 2018.
- Netherland, Sewell and Associates, Inc. (NSAI), completed their estimate of the Company's petroleum reserves and contingent resources for the 100% owned Palm Valley and Dingo Fields and for the 50% owned Mereenie Oil and Gas Field. Company oil and gas reserves (net to Central) have increased substantially, with Proven (1P) gas reserves increasing 65% to 134PJ and Proven and Probable (2P) gas reserves increasing 37% to 169PJ.
- The Mereenie Facility Upgrade was completed on schedule resulting in a 44 TJ/day firm supply capacity and additional capacity on a non-firm basis.
- The Palm Valley gas field was successfully restarted.
- The Palm Valley 13 appraisal well was drilled to 2,242 metres encountering encouraging initial gas flows, with further production testing to commence following connection to the Palm Valley facilities.
- Central was formerly awarded ATP 2031 covering 77km^2 of coal seam gas acreage in Queensland.
- Santos has completed the seismic works as part of the Southern Amadeus Stage 2 farmout and elected to proceed to Stage 3 by drilling a well in EP112 to earn a 70% participating interest in the permit. A drilling location for the Dukas-1 well has been selected (free carry for Central under the Farmout), with drilling currently anticipated to commence in the first half of 2019.
- Queensland CSG exploration acreage (ATP 2031) continues to be progressed with drilling anticipated in Q2 2019.
- Leon Devaney, Stuart Baker and Katherine Hirschfeld were appointed as Directors providing strong technical, industry and market expertise as the Company undergoes transformational growth.
- Following completion of the gas acceleration programme ("GAP") and recent commencement of the NGP, financial modelling and technical work has been progressed to position the company for a potential refinancing later this year.

Review of Operations *(continued)*

- The Company remains committed to executing its strategy to create value for all shareholders, whilst recognising the importance of all stakeholders including the traditional owners, employees, customers and the communities in which we operate.
- With the NGP now delivering gas into the east coast market, we now focus on maximising the value of our existing production assets and delivering new growth opportunities for the Company.

Safety

Safety performance was excellent with no LTIs recorded despite significantly increased activity and manhours associated with the drilling of West Mereenie 26 and Palm Valley 13, the Mereenie Facility Upgrade and the Palm Valley Restart Project. A number of minor incidents occurred providing the opportunity to capture learnings and make improvements. Central's TRIFR (Total Recordable Injury Frequency Rate) was 5.22 at 31 December 2018.

Mereenie Oil and Gas Field (OL4 and OL5) – Northern Territory

(CTP – 50% interest [Operator], Macquarie Mereenie Pty Ltd – 50% interest))

During the half-year:

- Gas production averaged 14 TJ/d over the half-year and averaged the significantly higher level of 31 TJ/d over the last two weeks of December as the field supplied additional gas to Jemena for the commissioning of the Northern Gas Pipeline (NGP).
- Oil production averaged 498 barrels of oil per day over the half-year.
- The Mereenie Facility Upgrade was successfully completed on schedule and on budget and approximately 1 month prior to the commencement of NGP commercial operations. This project included the installation of two new inlet separators, restaging the existing Field Boost Compressors, the installation of a new Field Boost Compressor, refurbishment and restart of Plant 3 and upgrades to the control system. As a result, the Mereenie Gas Field now has 44 TJ/d of firm capacity.
- NSAI were engaged to provide an updated reserves estimate for the field which resulted in a 28% increase to 2P reserves.
- The West Mereenie 26 well was successfully drilled but did not encounter commercial flowrates. WM26 has been suspended pending a review of alternative options to commercialise the well.

Palm Valley Gas Field (OL3) – Northern Territory

(CTP – 100% Interest)

During the half-year:

- The Palm Valley Field was successfully restarted with minor works ongoing at the end of the half-year associated with upgrades to the produced water reinjection system.
- NSAI were engaged to provide an updated reserves estimate for the field which resulted in an 86% increase to 2P reserves.
- The Palm Valley 13 well was successfully drilled and encountered commercial gas flows. The well was suspended pending tie-in to the existing gathering system. The PV13 tie-in project is underway with commencement of construction expected early in 1Q2019.
- Gas production averaged 8 TJ/d over the period from commencement of sales on 29th October to the end of the half year. This is expected to increase once one more existing well and the Palm Valley 13 well are brought online.

Review of Operations *(continued)*

Dingo Gas Field (L7) and Dingo Pipeline (PL30) – Northern Territory

(CTP – 100% Interest)

During the half-year:

- The field continued to supply Owen Springs Power Station and gas production averaged 2 TJ/d over the half-year, with the remaining contracted volume subject to take-or-pay provisions.
- NSAI were engaged to provide an updated reserves estimate for the field which resulted in a 23% increase to 2P reserves.
- The Water Bath Heater was successfully installed during the half-year resulting in significantly reduced consumption of methanol.

Surprise Oil Field (L6) – Northern Territory

(CTP – 100% Interest)

During the half-year:

- The field remained shut-in. A review is underway on options to restart the field to determine whether there is a viable economic case for restart.

Exploration Review

ATP 909, ATP 911 and ATP 912, Southern Georgina Basin, Queensland

(CTP – 100% interest)

During the half-year:

- Central Petroleum submitted an application for Project Status with the Queensland Department of Natural Resources, Mines and Energy ("DNRME"). The Company continued to consult with DNRME on the renewal applications and plans to submit the renewal early in 2019.

Southern Amadeus Joint Venture – EP82, EP105, EP125

(EP82 and EP105 Santos Ltd – 40% interest [Operator], CTP – 60% interest)
(EP125 Santos Ltd – 70% interest [Operator], CTP – 30% interest)

During the half-year:

- Santos completed the seismic works as part of the Southern Amadeus Stage 2 farmout through the acquisition of 1,337 line km in EP82, EP112 and EP125, earning 40% interest in EP82 and EP105.
- Additional large sub-salt leads targeting the Heavitree Quartzite have been matured through interpretation of newly acquired seismic and potential field data.

Santos Stage 3 Farm out – Southern Amadeus Basin, Northern Territory

(EP112 Santos Ltd – earning 70% [Operator], CTP – 30% interest)

During the half-year:

- Following on from the 2018 seismic acquisition, Santos completed the seismic interpretation over the Dukas prospect and the Joint Venture agreed on a drilling location.
- Santos continued to work on drilling and landholder approvals, with the drilling of Dukas-1 currently anticipated to commence in the first half of 2019.

Exploration Review *(continued)*

Amadeus Basin Granted and Application Permits (includes EP115 North Mereenie Block), Northern Territory

During the half-year:

- Seismic reprocessing of 243km of vintage 2D seismic data has been completed, satisfying the Year 2 work program for EP 115. The reprocessing will inform the planning of Year 3 seismic acquisition in 2019.
- Additional leads and prospects were matured by integrating available seismic, potential field and outcrop data.
- Native title negotiations are ongoing in application areas.

Ooraminna Field, Northern Territory

(CTP—100% interest)

During the half-year:

- The planned Ooraminna appraisal well was deferred from the half-year to enable learnings to be captured from the results of West Mereenie-26 and Palm Valley-13.
- An application has been made for a one year suspension of the permit obligation to drill the well. If successful, this will require the well to be drilled by March 2020.

Wiso Basin Application Permits, Northern Territory

(CTP—100% interest)

During the half-year:

- Native title negotiations are ongoing in application areas.

Operating and Financial Review

Risks

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

General Risks

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

- fluctuations in economic conditions in Australia and internationally, including fluctuations in economic growth, interest rates, exchange rates, inflation, and employment;
- fluctuations in stock markets, domestically and internationally;
- changes in government policies including fiscal policy, monetary policy, and foreign policy;
- Changes in market pricing risk, including gas prices and transportation costs/access.
- changes in political conditions; and
- natural disasters and catastrophic events.

Cash Flow and Liquidity Risk

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

Operating and Financial Review (continued)

Risks *(continued)*

Exploration & Appraisal Risk

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

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

Oil & Gas Estimates

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

Environmental Risk

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

Operating and Insurance Risks

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

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

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

Competition and Human Resource Risk

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

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

Health, Safety and Security Risks

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

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

Operating and Financial Review (*continued*)

Risks *(continued)*

Pipeline Tariff Risk

Central commenced selling gas into the east coast market following commencement of the Northern Gas Pipeline ("NGP") in January 2019. Currently, all sales into the east coast market are sold ex-field with customers responsible for transportation. The east coast gas market is currently undergoing a restructuring of supply and demand following the commencement of three LNG projects in Queensland. This has placed significant upward pressure on delivered gas prices to the east coast and changed pipeline constraints. Central's ex-field gas price for sales into the east coast however, will in part, depend upon pipeline tariffs which are themselves remain under regulatory review and implementation by Federal Government agencies. Access and regulation of gas transportation pipelines and gas market dynamics may be material to Central's ex-field gas pricing received from east coast customers.

Business Strategy

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

Central's business strategy was bolstered significantly on 1 September 2015 when Central completed the acquisition of 50% of Mereenie from Santos and became Operator for the Joint Venture. The implementation of this business strategy has made Central a substantial onshore domestic gas producer, with approximately 15.9 TJ/d (5.8 PJ p.a.) equity accounted from gas sales contracts being delivered during the half year ending 31 December 2018. Central undertook an appraisal drilling programme to increase uncontracted 2P reserves. Whilst the results of the first appraisal well (WM 26 at Mereenie) were disappointing, the PV 13 appraisal well at Palm Valley encountered encouraging initial flow rates and is currently being tied in to existing production facilities. A reserves review as at 30 June 2018 resulted in an increase of 37% in 2P reserves to 169PJ.

Both the Mereenie and Palm Valley fields have undergone substantial surface facility upgrade projects designed to maximise sales capacity and accelerate delivery of existing 2P reserves under the Gas Acceleration Programme (GAP).

With the Mereenie, Palm Valley and Dingo fields under our common operatorship, Central is now in a unique position to benefit from the NGP, which commenced transporting gas from the Northern Territory to the eastern seaboard in January 2019. This project was driven by clear fundamentals of a domestic gas shortfall on the east coast and underexplored onshore gas potential in the Northern Territory. In linking supply and demand, Central's business strategy of acquiring gas assets and uncontracted reserves in advance of the NGP pipeline positioned it to be a direct beneficiary.

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

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

Key Financial and Operating Data (Segment Reporting)

Central derives its revenues and profits from its producing assets segment; specifically the production and sales of natural gas from Palm Valley and Dingo, and natural gas and crude oil from Mereenie.

Central continues to explore for hydrocarbons which are reported in the exploration segment.

Operating and Financial Review (*continued*)

A summary of consolidated revenues and results for the half-year by segment is set out below:

	Segment Revenues		Segment EBITDAX[1]		Segment Results[2]	
Financial Data	31 Dec 18 $ million	31 Dec 17 $ million	31 Dec 18 $ million	31 Dec 17 $ million	31 Dec 18 $ million	31 Dec 17 $ million
Producing Assets	20.02	17.67	5.88	8.73	(15.04)	0.19
Development Assets	-	-	-	-	-	-
Exploration Assets	-	-	-	0.28	(0.47)	(0.88)
Unallocated Items	-	-	(3.12)	(2.86)	(3,57)	(3.23)
Total Group	20.02	17.67	2.76	6.15	(19.08)	(3.92)

Sales Data[3]	31 Dec 18	31 Dec 17
<u>Gas Sales (TJs)</u>		
Dingo Gas Field	378	375
Mereenie Gas Field	2,059	2,170
Palm Valley Gas Field	484	-
Total Gas Sales (GJs)	**2,921**	**2,545**
<u>Oil Sales (Bbls)</u>		
Mereenie Oil	43,727	54,000
Total Oil Sales (Bbls)	**43,727**	**54,000**

[1] *Earnings before Interest, tax, depreciation, amortisation, impairment and exploration expense*

[2] *Segment results are earnings after tax, which is the measure of segment result that is reported to the executive management team to assess the performance of the operating segments against total reported accounting profit.*

[3] *Sales volumes include gas physically supplied or forfeited under take or pay contracts. The volumes do not include quantities able to be invoiced under take or pay contracts where a future right to take gas still exists.*

Revenue

The Group recorded $20.0 million of operating revenue for the period compared to $17.7 million for the previous corresponding period, an increase of 13.3%. The increase reflects higher gas volumes associated with gas supplied to Jemena for the commissioning of the Northern Gas Pipeline ("NGP").

The NGP became fully operational in early January 2019. This will result in significant additional sales volumes in the second half of the financial year to 30 June 2019, and beyond.

Cost of Sales

Cost of Sales increased by $5.2M over the previous corresponding period. The increase was primarily attributable to the following non-recurring items:

- Palm Valley operating costs higher by $4.0M compared to the previous corresponding period as a result of the field restarting production in late October 2018. Included in this number were $2.1M of pre-production operational readiness costs incurred prior to recommencement of production as part of the GAP (refer also to underlying EBITDAX reconciliation provided below).
- Non-cash contract provisioning under gas sales agreements of $0.9M due ot late commencement of the NGP (refer also Note 9 to the financial statements).
- Other minor net increases of $0.3M, primarily attributable to GAP readiness at Mereenie.

The NGP became operational on 3 January 2019 and increased volumes are now being delivered to customers on the East Coast.

EBITDAX

Segment EBITDAX are earnings before interest, tax depreciation, amortisation, impairment and exploration. EBITDAX is used by management as an indicative measure of underlying cash profit from operations as it excludes non-cash items and the costs of finance.

Operating and Financial Review (*continued*)

It should be noted however that share based payments (2018: $567,198 2017: $1,049,130) are not excluded from the unallocated items in the tables above but are also non-cash items. The result does not include amounts from take or pay gas contracts until the gas is taken or forfeited by the customer.

Underlying EBITDAX

The reconciliation below shows underlying EBITDAX was $5.75M compared to $6.15M for the previous corresponding period.

Exploration costs expensed during the half year amounted to $13.64 million compared to $1.70 million in the previous corresponding period. This reflected remaining costs of the West Mereenie 26 and Palm Valley 13 appraisal wells. All exploration and appraisal drilling costs are expensed in accordance with the Group's accounting policy for exploration and evaluation, regardless of their success.

	Half Year ended 31 December	
	2018	**2017**
	$ million	**$ million**
Statutory loss before tax	(19.08)	(3.92)
Adjustments:		
Restatement of financial liability[1]	(0.05)	0.38
Palm Valley operational readiness costs[2]	2.11	-
Sales contract provisioning due to delay of NGP[3]	0.88	-
Underlying loss before tax	(16.14)	(3.54)
Exploration	13.64	1.70
Interest	3.85	4.35
Depreciation and amortisation	4.35	4.02
Underlying EBITDAX	**5.70**	**6.53**

1. *Relates to prepaid gas sales agreement with a cash settlement option. If the cash settlement option is exercised payment will be satisfied out of future gas sales revenues from those gas sales agreements to which the cash settlement option is linked.*
2. *Operating costs incurred in respect of the Palm Valley gas field prior to recommencement of production (operational readiness).*
3. *Provision for customer reimbursements under gas sales agreements (refer also to Note 9)*

Other Items

Net employee costs rose by 0.58M compared the prior corresponding period, reflecting efforts to strengthen the executive management team ahead the next phase of growth in calendar year 2019. The prior corresponding period result included a $0.28 million gain from the disposal of interests in exploration application areas.

Events since the end of the Half Year

No matter or circumstance has arisen that will affect the Group's operations, results or state of affairs.

Auditor's Independence Declaration

A copy of the auditor's independence declaration as required under section 307C of the Corporations Act 2001 is set out on page 12.

This report is made in accordance with a resolution of directors.

Martin Kriewaldt
Chairman
Brisbane
20 February 2019

AUDITOR'S DECLARATION OF INDEPENDENCE

31 December 2018

pwc

Auditor's Independence Declaration

As lead auditor for the review of Central Petroleum Limited for the half-year ended 31 December 2018, I declare that to the best of my knowledge and belief, there have been:

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

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

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

Timothy J Allman
Partner
PricewaterhouseCoopers

Brisbane
20 February 2019

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the half-year ended 31 December 2018

	Notes	2018 $	2017 $
Operating revenue		20,022,261	17,673,716
Cost of sales		(14,197,269)	(8,996,266)
Gross profit		5,824,992	8,677,450
Other income	4	217,030	530,059
Share based employment benefits		(567,198)	(1,049,130)
General and administrative expenses		(481,708)	(358,261)
Depreciation and amortisation		(4,353,775)	(4,021,100)
Employee benefits and associated costs		(2,229,204)	(1,647,626)
Exploration expenditure		(13,640,645)	(1,704,973)
Finance costs		(3,846,657)	(4,345,047)
Loss before income tax		(19,077,165)	(3,918,628)
Income tax credit		-	-
Loss for the half-year		(19,077,165)	(3,918,628)
Other comprehensive loss for the half-year, net of tax		-	-
Total comprehensive loss for the half-year		(19,077,165)	(3,918,628)
Total comprehensive loss attributable to members of the parent entity		(19,077,165)	(3,918,628)
Earnings per share			
Basic and diluted loss per share (cents)		(2.70)	(0.64)

The above consolidated statement of comprehensive income should be read in conjunction with the accompanying notes.

CONSOLIDATED BALANCE SHEET

As at 31 December 2018

	Notes	31 Dec 2018 $	30 Jun 2018 $
ASSETS			
Current assets			
Cash and cash equivalents	5	10,941,847	27,222,845
Trade and other receivables		13,860,065	6,631,642
Inventories		3,572,443	3,575,480
Other financial assets		-	2,333,333
Total current assets		28,374,355	39,763,300
Non-current assets			
Property, plant and equipment	6	112,892,104	103,853,369
Exploration assets		8,898,767	8,898,767
Intangible assets		143,100	156,017
Other financial assets		2,724,239	2,535,915
Goodwill		3,906,270	3,906,270
Total non-current assets		128,564,480	119,350,338
Total assets		**156,938,835**	**159,113,638**
LIABILITIES			
Current liabilities			
Trade and other payables		8,133,158	8,113,667
Deferred revenue		10,537,214	7,283,068
Interest-bearing liabilities	7	13,563,440	3,727,338
Other financial liabilities	8	38,600	38,600
Provisions	9	3,498,522	3,406,515
Total current liabilities		35,770,934	22,569,188
Non-current liabilities			
Deferred revenue		15,595,476	13,678,980
Interest-bearing liabilities	7	72,700,963	74,599,221
Other financial liabilities	8	15,617,595	15,362,506
Provisions	9	28,442,338	25,840,435
Total non-current liabilities		132,356,372	129,481,142
Total liabilities		**168,127,306**	**152,050,330**
Net assets		**(11,188,471)**	**7,063,308**
EQUITY			
Contributed equity	10	197,776,487	197,776,487
Reserves	10	24,289,170	23,463,784
Accumulated losses		(233,254,128)	(214,176,963)
Total equity		**(11,188,471)**	**7,063,308**

The above consolidated balance sheet should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the half-year ended 31 December 2018

		Attributable to owners of Central Petroleum Limited			
	Notes	**Contributed Equity**	**Option Reserve**	**Accumulated Losses**	**Total**
		$	**$**	**$**	**$**
Balance at 1 July 2017		**172,301,532**	**21,841,455**	**(200,100,834)**	**(5,957,847)**
Loss for the half-year		-	-	(3,918,628)	(3,918,628)
Other comprehensive income		-	-	-	-
Total comprehensive loss for the half-year		-	-	(3,918,628)	(3,918,628)
Transactions with owners in their capacity as owners					
Share based payments		-	1,049,130	-	1,049,130
Share issues		27,250,000	-	-	27,250,000
Share issue costs		(1,775,045)	-	-	(1,775,045)
Total transactions with owners		25,474,955	1,049,130	-	26,524,085
Balance at 31 December 2017		**197,776,487**	**22,890,585**	**(204,019,462)**	**16,647,610**
Balance at 1 July 2018		**197,776,487**	**23,463,784**	**(214,176,963)**	**7,063,308**
Loss for the half-year		-	-	(19,077,165)	(19,077,165)
Other comprehensive income		-	-	-	-
Total comprehensive loss for the half-year		-	-	(19,077,165)	(19,077,165)
Transactions with owners in their capacity as owners					
Share based payments		-	567,198	-	567,198
Options issued for financing		-	258,188	-	258,188
Total transactions with owners		-	825,386	-	825,386
Balance at 31 December 2018		**197,776,487**	**24,289,170**	**(233,254,128)**	**(11,188,471)**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the half-year ended 31 December 2018

	2018 $	2017 $
Cash flows from operating activities		
Receipts from customers	18,022,287	16,656,043
Interest received	211,692	199,385
Other income received	22,175	19,576
Interest and borrowing costs	(3,117,010)	(2,993,187)
Payments to suppliers and employees (inclusive of GST)	(29,618,196)	(13,666,293)
Net cash inflow/(outflow) from operating activities	(14,479,052)	215,524
Cash flows from investing activities		
Payments for interest in Mereenie assets	-	-
Payments for property, plant and equipment	(11,946,955)	(957,832)
Payment for security bonds	(188,324)	-
Redemption of security bonds	2,333,333	70,813
Proceeds from the sale of interests in exploration permits	-	280,000
Deposits received for sale of exploration permits	-	30,000
Net cash outflow from investing activities	(9,801,946)	(577,019)
Cash flow from financing activities		
Proceeds from contributed equity	-	27,250,000
Payments for capital raising costs	-	(1,775,044)
Proceeds from borrowings	10,000,000	-
Repayment of borrowings	(2,000,000)	(2,000,000)
Net cash inflow/(outflow) from financing activities	8,000,000	23,474,956
Net increase/(decrease) in cash and cash equivalents	**(16,280,998)**	**23,113,461**
Cash and cash equivalents at the beginning of the half-year	**27,222,845**	**5,478,140**
Cash and cash equivalents at the end of the half-year	**10,941,847**	**28,591,601**

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the half-year ended 31 December 2018

1. Basis of Preparation of Half-Year Report

This condensed consolidated interim financial report for the half-year reporting period ended 31 December 2018 has been prepared in accordance with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Act 2001 (Cth)*.

This condensed consolidated interim financial report does not include all the notes of the type normally included in an annual financial report. Accordingly, this report is to be read in conjunction with the annual report for the year ended 30 June 2018 and any public announcements made by Central Petroleum Limited during the interim reporting period in accordance with the continuous disclosure requirements of the Corporations Act 2001.

The accounting policies adopted are consistent with those of the previous financial year and corresponding interim reporting period unless otherwise stated.

(a) Going Concern

The interim financial report has been prepared on a going concern basis which contemplates continuity of normal business activities and the realisation of assets and settlement of liabilities in the ordinary course of business.

During the period ended 31 December 2018, Central Petroleum Limited ("Central") incurred a Loss of $19,077,165 (2017: Loss of $3,918,628) and had a net cash outflow from operating activities (including exploration drilling) of $14,479,052 (2017: net cash inflow of $215,524).

At 31 December 2018 the Group had an overall net liability position of $11,188,471 (30 June 2018 net assets of $7,063,308). The net liability position has arisen due to a combination of factors and includes recognition of deferred contract revenue of $26,131,690 and a financial liability of $15,553,262 as disclosed in Note 8 relating to the second and third years of the Macquarie Bank Limited Gas Sales and Prepayment Agreement ("MBL GSPA") entered into in May 2016.

Settlement of the MBL GSPA financial liability will be satisfied either by physical delivery of gas from existing 1P reserves or paid out of the proceeds of the sale of gas contracted under the EDL GSA for which no corresponding asset is recognised in the balance sheet at 31 December 2018.

The Group continually monitors its cash flow requirements to ensure it has sufficient funds to meet its contractual commitments and adjust its spending, particularly with respect to discretionary exploration activity and corporate overhead, accordingly. Supported by the cash assets at 31 December 2018 of $10,941,847, and its cash flow forecasts, the Group forecasts that over at least the next 12 months, it will have sufficient funds to meet its commitments and continue to pay its debts as and when they fall due. As at 31 December 2018, the Company had a $7.5 million undrawn debt facility available from Macquarie Bank. This was subsequently drawn down in January 2019. In addition the Company has a $10 million Equity Line of Credit with Long State Investment Limited which remains undrawn.

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

(b) 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 2018. The adoption of these new and revised Standards and Interpretations has not resulted in any material change to the Group's accounting policies, with the exception of AASB 15 *Revenue from Contracts with Customers* (AASB 15).

The Group has adopted AASB 15 *Revenue from Contracts with Customers* and AASB 9 *Financial Instruments* (AASB 9) from 1 July 2018.

1. Basis of Preparation of Half-Year Report (*continued*)

(i) AASB 15 Revenue from contracts with customers

AASB 15 in based on the principle that revenue is recognised when control of a good or service transfers to a customer. This standard replaced AASB 11 *Construction Contracts*, AASB 118 *Revenue* and related IFRIC Interpretations.

In accordance with the transition provisions of AASB 15, the Group has adopted the full retrospective transition approach, where any adjustment to historical revenue transactions (that impacts net profit) are recorded against opening retained earnings as at 1 July 2017. The Group undertook a detailed review of its revenue contracts that were entered into during the transition period and concluded that there were no adjustments required to net profit or opening retained earnings on transition.

Some of the Group's sales such as crude oil contain provisional pricing features which are considered to be embedded derivatives. AASB 15 will not change the assessment of the existence of embedded derivatives. These embedded derivatives are outside of the scope of AASB 15 and are accounted for in accordance with AASB 9.

The group does not currently enter into any gas swap agreements nor is it in any "under-lift" position which may impact revenue recognition.

Accounting policy

Revenue

Revenue from contracts with customers is recognised in the income statement when or as the Group transfers control of goods or services to a customer at the amount to which the Group expects to be entitled. If the consideration promised includes a variable amount, the Group estimates the amount of consideration to which it will be entitled.

Revenue from sale of hydrocarbons

Revenue from the sale of hydrocarbons is recognised using the "sales method" of accounting. The sales method results in revenue being recognised based on volumes sold under contracts with customers, at the point in time where performance obligations are considered met. Generally, regarding the sale of hydrocarbon products, the performance obligation will be met when the product is delivered to the specified measurement point (gas) or point of loading/unloading (liquids).

Contract liabilities

A contract liability is recorded for obligations under sales contracts to deliver natural gas in future periods for which payment has already been received (including "take or pay" arrangements).

(ii) AASB 9 Financial instruments

AASB 9 addresses the classification, measurement and derecognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new expected credit loss model for calculating the impairment of financial assets. This standard replaced AASB 139 *Financial Instruments: Recognition and Measurement*.

The group adopted AASB 9 on 1 July 2018 and applied the requirements of the standard retrospectively in line with the requirements of the standard. There were no significant differences between the previous carrying amount and the revised carrying amount of financial assets and liabilities. Furthermore there were no changes in the classification of financial assets and liabilities.

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

The impairment model in AASB 9 is based on the premise of providing for expected losses. The change in the impairment model has no significant impact to the group's impairment policy.

1. Basis of Preparation of Half-Year Report (*continued*)

(c) Impact of Standards Issued but not yet applied by the Entity

(i) AASB 16 Leases

AASB 16 was issued in February 2016. The standard is mandatory for the Group from 1 July 2019. The group does not intend to adopt the standard before its effective date.

The new standard 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 group does not have any existing finance leases. The standard will affect the group's operating leases. As at the reporting date, the Group has operating lease commitments of $1,507,048. The group is in the process of assessing 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.

On initial application, the group intends to make the election under the new standard to measure lease liability at the present value of the remaining lease payments, discounted using the group's incremental borrowing rate at the date of initial application and to record a right of use asset equal to the lease liability.

Some of the commitments may be covered by the exception for short-term and low-value leases and some commitments may relate to arrangements that will not qualify as leases under AASB 16. The group intends to also take advantage of practical expedients under the new standard in respect of applying a single discount rate to a portfolio of assets with similar characteristics, excluding leases which end within 12 months of the transition date, and for certain classes of asset, elect not to account for non-lease and lease components as a single lease component.

2. Significant Changes in the Current Reporting Period

The financial position and performance of the group was particularly affected by the following events and transactions during the half-year ended 31 December 2018:

- Exploration expenditure increased during the half year reflecting the drilling of West Mereenie 26 and Palm Valley 13 appraisal wells.
- The Mereenie expansion project was completed in time to supply gas for transportation via the NGP to customers on the East Coast. NGP commissioning was completed early January 2019.
- Gas was sold under a short terms GSA to Jemena during the half year for commissioning of the Northern Gas Pipeline.
- Additional borrowings of $10 million were drawn down to help fund the Mereenie expansion project, as well as Palm Valley restart and plant upgrades. These additional borrowings are repayable during calendar year 2019. A further $7.5million facility with Macquarie was available but undrawn at 31 December 2018.

For a detailed discussion about the group's performance and financial position please refer to our review of operations contained in the Directors' Report on pages 4 to 11.

3. Segment Reporting

The Group has identified its operating segments based on the internal reports that are reviewed and used by the executive management team (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.

(a) Gas and Oil Producing Assets

The production and sale of natural gas and crude oil.

(b) Development Assets

The development of oil and gas fields.

(c) Exploration Assets

The exploration and evaluation of permit areas.

(d) 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.

3. Segment Reporting *(continued)*

(e) 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. Financing requirements, finance income, finance costs and taxes are managed at a Group level. The consolidated entity's operations are wholly in one geographical location being Australia.

	Producing Assets 31 Dec 2018 $	Exploration Assets 31 Dec 2018 $	Unallocated Items 31 Dec 2018 $	Consolidated 31 Dec 2018 $
Revenue	20,022,261	-	-	20,022,261
Cost of sales	(14,197,269)	-	-	(14,197,269)
Gross profit	**5,824,992**	**-**	**-**	**5,824,992**
Other income	54,373	79	162,578	217,030
Share based employment benefits[1]	-	-	(567,198)	(567,198)
General and administrative expenses	-	-	(481,708)	(481,708)
Employee benefits and associated costs	-	-	(2,229,204)	(2,229,204)
EBITDAX[2]	**5,879,365**	**79**	**(3,115,532)**	**2,763,912**
Depreciation and amortisation	(4,203,085)	-	(150,690)	(4,353,775)
Exploration expenditure	(13,192,606)	(448,039)	-	(13,640,645)
Finance costs	(3,525,965)	(22,409)	(298,283)	(3,846,657)
Profit/(loss) before income tax	**(15,042,291)**	**(470,369)**	**(3,564,505)**	**(19,077,165)**
Taxes	-	-	-	-
Profit / (Loss) for the period	**(15,042,291)**	**(470,369)**	**(3,564,505)**	**(19,077,165)**

[1] Share based employment benefits are a non-cash item.
[2] EBITDAX is Earnings before Interest, Taxation, Depreciation and Amortisation, Impairment and Exploration expense.

	Producing Assets 31 Dec 2017 $	Exploration Assets 31 Dec 2017 $	Unallocated Items 31 Dec 2017 $	Consolidated 31 Dec 2017 $
Revenue	17,673,716	-	-	17,673,716
Cost of sales	(8,996,266)	-	-	(8,996,266)
Gross profit	**8,677,450**	**-**	**-**	**8,677,450**
Other income	49,619	280,000	200,440	530,059
Share based employment benefits[1]	-	-	(1,049,130)	(1,049,130)
General and administrative expenses	-	-	(358,261)	(358,261)
Employee benefits and associated costs	-	-	(1,647,626)	(1,647,626)
EBITDAX[2]	**8,727,069**	**280,000**	**(2,854,577)**	**6,152,492**
Depreciation and amortisation	(3,894,765)	-	(126,335)	(4,021,100)
Exploration expenditure	(569,912)	(1,135,061)	-	(1,704,973)
Finance costs	(4,072,991)	(20,753)	(251,303)	(4,345,047)
Profit/(loss) before income tax	**189,401**	**(875,814)**	**(3,232,215)**	**(3,918,628)**
Taxes	-	-	-	-
Profit / (Loss) for the period	**189,401**	**(875,814)**	**(3,232,215)**	**(3,918,628)**

[1] Share based employment benefits are a non-cash item.
[2] EBITDAX is Earnings before Interest, Taxation, Depreciation and Amortisation, Impairment and Exploration expense

3. Segment Reporting (*continued*)

(e) Performance Monitoring and Evaluation (*continued*)

	Producing Assets	Exploration Assets	Corporate Items	Consolidated
	$	$	$	$
Total Segment Assets				
31 December 2018	139,407,023	11,651,269	5,880,543	156,938,835
30 June 2018	121,601,949	12,625,994	24,885,695	159,113,638
Total Segment Liabilities				
31 December 2018	(153,381,883)	(2,622,459)	(12,122,964)	(168,127,306)
30 June 2018	(136,584,039)	(2,828,327)	(12,637,964)	(152,050,330)

Revenue from external customers by geographical location of production:	31 Dec 2018 $	31 Dec 2017 $
Australia	20,022,261	17,673,716

Non-current assets by geographical location:	31 Dec 2018 $	30 Jun 2018 $
Australia	128,564,480	119,350,338

(f) Major Customers

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

	31 Dec 2018 $	% of Sales Revenue	31 Dec 2017 $	% of Sales Revenue
Largest customer	5,194,289	26%	4,629,921	26%
Second largest customer	3,685,455	18%	3,838,840	22%
Third largest customer	2,881,752	14%	2,959,059	17%
Fourth largest customer	2,494,847	12%	2,419,102	14%
Fifth largest customer	2,465,028	12%	2,036,678	12%

4. Other Income

	31 Dec 2018 $	31 Dec 2017 $
Profit on disposal of interests in Exploration tenements	-	280,000
Interest revenue	196,230	230,483
Other	20,800	19,576
	217,030	**530,059**

5. Cash and Cash Equivalents

Cash at bank and on hand comprising:	31 Dec 2018 $	30 Jun 2018 $
Corporate (a)	9,519,264	26,706,273
Joint arrangements (b)	1,422,583	516,572
	10,941,847	**27,222,845**

(a) $4,555,287 of this balance relates to restricted cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (30 June 2018: $1,782,026), including, but not limited to, operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, capital expenditure and debt servicing.

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

6. Property, Plant and Equipment

	Freehold land and buildings $	Producing assets $	Plant and equipment $	Total $
30 June 2018				
Cost	3,868,743	84,823,014	49,442,072	138,133,829
Accumulated depreciation and impairment	(989,728)	(11,992,080)	(21,298,652)	(34,280,460)
Net book amount	**2,879,015**	**72,830,934**	**28,143,420**	**103,853,369**
31 December 2018				
Opening net book amount	2,879,015	72,830,934	28,143,420	103,853,369
Additions	-	-	12,672,192	12,672,192
Adjustment to restoration provisions	-	685,737	5,596	691,333
Disposals and write offs	-	-	(780)	(780)
Depreciation charge	(175,101)	(2,466,816)	(1,682,093)	(4,324,010)
Closing net book amount	**2,703,914**	**71,049,855**	**39,138,335**	**112,892,104**
31 December 2018				
Cost	3,868,743	85,508,751	62,118,965	151,496,459
Accumulated depreciation and impairment	(1,164,829)	(14,458,896)	(22,980,630)	(38,604,355)
Net book amount	**2,703,914**	**71,049,855**	**39,138,335**	**112,892,104**

7. Interest Bearing Liabilities

		31 Dec 2018 $	30 Jun 2018 $
(a)	Interest bearing liabilities (current)		
	Debt facilities	8,508,782	3,727,338
	Incitec Pivot Limited Gas Prepayment facility	5,054,658	-
		13,563,440	**3,727,338**
(b)	Interest bearing liabilities (non-current)[1]		
	Debt facilities	72,700,963	74,599,221
		72,700,963	**74,599,221**

The Macquarie Bank Facility consists of a number of tranches. Tranches A to D are structured as 5 year partially amortising term loans with a maturity date of 30 September 2020. The interest costs are based on fixed spreads over the periodic Bank Bill Swap (BBSW) average bid rate. The Group does not have any interest rate hedging arrangements in place. The Group can repay the Facility in part or in whole at any time without a pre-payment penalty.

During the half year a Second Tranche D facility of $5 million and a Tranche E facility of $7.5 million were added to the total facility. These additional tranches are fully repayable by 31 December 2019, with principal repayments commencing 31 March 2019. Facility E remains undrawn at 31 December 2018.

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

1. The Group current ratio is at least 1:1, excluding amounts payable under the Macquarie debt facility.
2. PDP Cover Ratio is greater than 1.3:1. PDP Cover Ratio is defined as the net present value (using a 10% discount rate) of the proved, developed, producing reserves of the Palm Valley, Dingo and Mereenie oil and gas fields.
3. Financial indebtedness to trade creditors over 90 days from due date for payment does not exceed $5 million.

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

As part of a Gas Sales Agreement entered into with Incitec Pivot Limited ("IPL") in June 2018, IPL advanced $5 million to the Group in November 2018. Repayment of the advance will be made over four months against amounts owing by IPL from gas sales which commenced in January 2019. Interest on amounts outstanding under this facility accrues at 7% per annum.

8. Other financial liabilities

	31 Dec 2018 $	30 Jun 2018 $
Current		
Lease incentives received	38,600	38,600
	38,600	38,600
Non-Current		
Liabilities associated with forward gas sales agreements containing a cash settlement option	15,553,262	15,278,873
Lease incentives liabilities	64,333	83,633
Available to be taken after 12 months	15,617,595	15,362,506
Total Other Financial Liabilities	**15,656,195**	**15,401,106**

9. Provisions

	31 December 2018			30 June 2018		
	Current	Non-current	Total	Current	Non-current	Total
	$	$	$	$	$	$
Employee entitlements (a)	2,975,327	798,270	3,773,597	2,883,557	660,179	3,543,736
Restoration and rehabilitation (b)	523,195	22,624,825	23,148,020	522,958	21,639,197	22,162,155
Contract reimbursables (c)	-	875,000	875,000	-	-	-
Joint Venture production over-lift (d)	-	4,144,243	4,144,243	-	3,541,059	3,541,059
Total	**3,498,522**	**28,442,338**	**31,940,860**	**3,406,515**	**25,840,435**	**29,246,950**

Movements in Provisions

	Employee Entitlements (a) $	Restoration and Rehabilitation (b) $	Other (c) & (d $	Total $
Carrying amount at 1 July 2018	3,543,736	22,162,155	3,541,059	29,246,950
Charged/(credited) to profit or loss	784,874	35,306	1,478,184	2,298,364
Changes to restoration assets	-	691,333	-	691,333
Unwinding of discount	-	259,226	-	259,226
Amounts used during the half-year	(555,013)	-	-	(555,013)
Carrying amount at 31 December 2018	**3,773,597**	**23,148,020**	**5,019,243**	**31,940,860**

(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 Group does not have an unconditional right to defer settlement of these obligations. However, based on past experience the consolidated entity does not expect all employees to take the full amount of accrued leave or require payment within the next 12 months. The following amounts reflect leave that is not expected to be taken within the next 12 months.*

	31 Dec 2018	30 Jun 2018
Leave obligations expected to be settled after 12 months	773,515	778,897

(b) *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.*

(c) *Provision for customer reimbursements under gas sales agreements.*

(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.*

10. Contributed Equity and Reserves

	31 Dec 2018 $	30 Jun 2018 $
Share Capital		
707,081,966 ordinary shares	197,776,487	197,776,487
(30 June 2018: 707,081,966 ordinary shares)		
Reserves		
Share Options Reserve	24,289,170	23,463,784

	Half-Year Ended 31 December	
	2018 $	2017 $
Movements in Share Capital:		
Balance at start of year	197,776,487	172,301,532
Issues of ordinary shares	-	27,250,000
Transaction costs	-	(1,775,045)
Balance at the end of the half year	**197,776,487**	**197,776,487**
Movements in Share Options Reserve:		
Balance at start of year	23,463,784	21,841,455
Share based payments costs	567,198	1,049,130
Options issued for financing	258,188	-
Balance at the end of the half year	**24,289,170**	**22,890,585**

	2018 No. of securities	2017 No. of securities
Movements in Ordinary Shares on Issue during the half-year:		
Balance at the beginning of the half-year	707,115,793	433,197,647
Share issues under placement and entitlement offers	-	272,500,000
Exercise of Employee Share Rights under LTIP	2,876,183	1,384,319
Balance at the end of the half-year	**709,991,976**	**707,081,966**

10. Contributed Equity and Reserves *(continued)*

Share Rights[1] granted during the period

Date of Issue	Class	Expiry Date	Value on issue	Number Issued
02-Oct-2018	Unlisted employee share rights	05-Jan-2021	$0.067-$0.135	554,536
02-Oct-2018	Unlisted employee share rights	09-Feb-2021	$0.067	183,540
02-Oct-2018	Unlisted employee share rights	03-Oct-2022	$0.067	31,359
02-Oct-2018	Unlisted employee share rights	08-Dec-2022	$0.067-$0.135	12,003

[1] The number of rights to vest will be determined in accordance with the performance conditions as detailed in the Company's Long Term Incentive Plan. The exercise price is Nil.

Share Rights expired or cancelled during the period

Class	Expiry Date	Exercise Price	Number
Unlisted employee share rights - cancelled	-	-	-

Share Rights exercised during the period

Class	Exercise Date	Exercise Price	Number
Unlisted employee share rights	28-Nov-2018	Nil	2,876,183

Options granted during the period

Date of Issue	Class	Expiry Date	Exercise Price	Value on Issue	Number Issued
19-Oct-2018	Macquarie Bank -financing	31-Dec-2019	$0.14	$0.046	5,625,000

11. Contingencies and Commitments

(a) Exploration and Capital Commitments

The Group has the following capital expenditure commitments:

	Consolidated	
	31 Dec 2018 $	30 Jun 2018 $
Within 1 year	-	1,675,020
Later than 1year but not later than 3 years	-	-
Later than 3 years but not later than 5 years	-	-
Total	**-**	**1,675,020**

The Group has contingent exploration expenditure commitments on various permit areas held in Australia.

	Consolidated	
	31 Dec 2018 $	30 Jun 2018 $
Within 1 year	6,175,000	14,155,000
Later than 1year but not later than 3 years	45,580,000	13,325,000
Later than 3 years but not later than 5 years	17,050,000	11,050,000
Total	**68,805,000**	**38,530,000**

In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties and, as a result, obligations may be reduced or extinguished.

11. Contingencies and Commitments (*continued*)

(b) Operating Lease Commitments

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

	Consolidated	
	31 Dec 2018 **$**	**30 Jun 2018** **$**
Within 1 year	545,078	560,413
Later than 1 year but not later than 5 years	961,970	1,221,665
Total	**1,507,048**	**1,782,078**

(c) Contingent Liabilities

There were no changes to contingent liabilities as outlined in the previous annual financial report to 30 June 2018, except as noted below:

(i) GRR Litigation

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

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

12. Post Balance Date Events

There were no events that occurred subsequent to 31 December 2018 other than noted above or elsewhere in these accounts.

13. Related Party Transactions

There were no related party transactions during the period.

DIRECTORS' DECLARATION

31 December 2018

In the Directors' opinion:

The Financial Statements and notes set out on pages 13 to 28 are in accordance with the Corporations Act 2001, including:

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

(b) giving a true and fair view of the Consolidated Entity's financial position as at 31 December 2018 and of its performance for the half-year ended on that date, and

(b) there are reasonable grounds to believe that Central Petroleum Limited will be able to pay its debts as and when they become due and payable.

This declaration is made in accordance with a resolution of Directors.

Martin Kriewaldt
Chairman
Brisbane

20 February 2019

INDEPENDENT AUDITOR'S REVIEW

pwc

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

Report on the Half-Year Financial Report

We have reviewed the accompanying half-year financial report of Central Petroleum Limited (the Company), which comprises the consolidated balance sheet as at 31 December 2018, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the half-year ended on that date, selected other explanatory notes and the directors' declaration for Central Petroleum Limited. The Group comprises the Company and the entities it controlled during that half-year.

Directors' responsibility for the half-year financial report

The directors of the Company are responsible for the preparation of the half-year 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 half-year financial report that is free from material misstatement whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express a conclusion on the half-year financial report based on our review. We conducted our review in accordance with Australian Auditing Standard on Review Engagements ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity*, in order to state whether, on the basis of the procedures described, we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 31 December 2018 and its performance for the half-year ended on that date; and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*. As the auditor of Central Petroleum Limited, ASRE 2410 requires that we comply with the ethical requirements relevant to the audit of the annual financial report.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Independence

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

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Conclusion
Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the half-year financial report of Central Petroleum Limited is not in accordance with the *Corporations Act 2001* including:

1. giving a true and fair view of the Group's financial position as at 31 December 2018 and of its performance for the half-year ended on that date;
2. complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

PricewaterhouseCoopers

PricewaterhouseCoopers

Timothy J Allman
Partner

Brisbane
20 February 2019

CORPORATE DIRECTORY

31 December 2018

Directors

Martin D Kriewaldt, BA, LL.B (Hons 1st), University Medal, FAICD (Life), AICDQ Gold Medal
Independent Non-Executive Chairman

Stuart Baker BE(Elec), MBA, AICD (Appointed 7 December 2018)
Independent Non-Executive Director

Richard Cottee BA, LLB (Hons)
Independent Non-Executive Director

Leon Devaney BSc MBA (appointed 14 November 2018)
Executive Director

Wrixon F Gasteen BE (Mining) (Hons), Qld, MBA (Distinction), Geneva
Independent Non-Executive Director

Katherine Hirschfeld BE (Chem) HonFIEAust FTSE FIChemE FAICD (appointed 7 December 2018)
Independent Non-Executive Director

Company Secretaries

Joseph P Morfea, FAIM, GAICD
Daniel C M White LLB, BCom, LLM

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Auditors

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Share Registrar

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West End, QLD 4101
Telephone: +61(0)7 3237 2100
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Stock Exchange Listing

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