OPERATING ACTIVITIES REPORT AND ASX APPENDIX 5B
For the Quarter Ended 31 December 2019

REVIEW OF OPERATIONS FOR THE QUARTER ENDED 31 DECEMBER 2019 ("THE QUARTER")

HIGHLIGHTS

- Sales volumes increased 6.7% to 3.7 PJE (Petajoule equivalent), up from 3.5 PJE in the September quarter (including 0.3 PJ of purchased gas in each quarter) with total sales revenue of $18.5 million, up 7.5% from $17.2 million on the September quarter.
- Announced a major exploration programme for CY2020 consisting of five high-graded drillable prospects and two appraisal tests in the Amadeus Basin. The programme has a risked estimated prospective resource of 205 PJ of gas and 9 mmboe of oil. Funding is anticipated to be sourced through a farmout process which is currently underway.
- Announced a new joint gas sales agreement (GSA) for the supply of up to 21.9 PJ of 'firm' and 'as-available' gas to AGL Energy over three years from 1 January 2020, partially replacing maturing contracts. Central has a 50% contractual obligation for gas supply under the GSA, but it expects to receive the benefit of the majority of the revenue during the first two contract years, under new portfolio balancing arrangements with its Mereenie JV partner.
- Planning for the Range Gas Project has progressed with the upcoming pilot well programme and pre-Final Investment Decision (FID) activities expected to lead to a conversion of 2C contingent gas resource to certified 2P reserves.
- Commenced the farm-out of the CY2020 exploration programme and appointed Flagstaff Partners as advisors in January 2020. The initial response has been encouraging, with several parties already expressing interest.
- Cash balance at the end of the quarter was $14.9 million, down $1.6 million from $16.5 million at 30 September 2019:
  - Net cash flow from operations (before exploration and finance costs) was $5.7 million;
  - Net cash flow from operations, after exploration, interest and unallocated G&A, was $3.9 million, including a once-off tax-related payment of $0.6 million; and
  - Principal repayments under debt facilities were $4.7 million with Macquarie pre-sale gas deliveries of 437 TJ. Total debt repayments made in CY2019 were as forecast at $21.5 million, reducing net debt from its peak of $94.3 million following the last drawdown in January 2019 to $72.8 million at 31 December 2019.

Central Petroleum MD & CEO, Leon Devaney said: "*This was a strong quarter for Central, not only in operations, but also in terms of our growth strategy. We announced a major exploration programme for CY2020 and progressed the Range Gas Project toward FID early next year. Combined, these two initiatives enable us to target a tripling of our gas resources and gas sales by 2022 and potentially launch a major new oil production province in our Western permits.*"

PRODUCTION ACTIVITIES

Total Sales Volumes

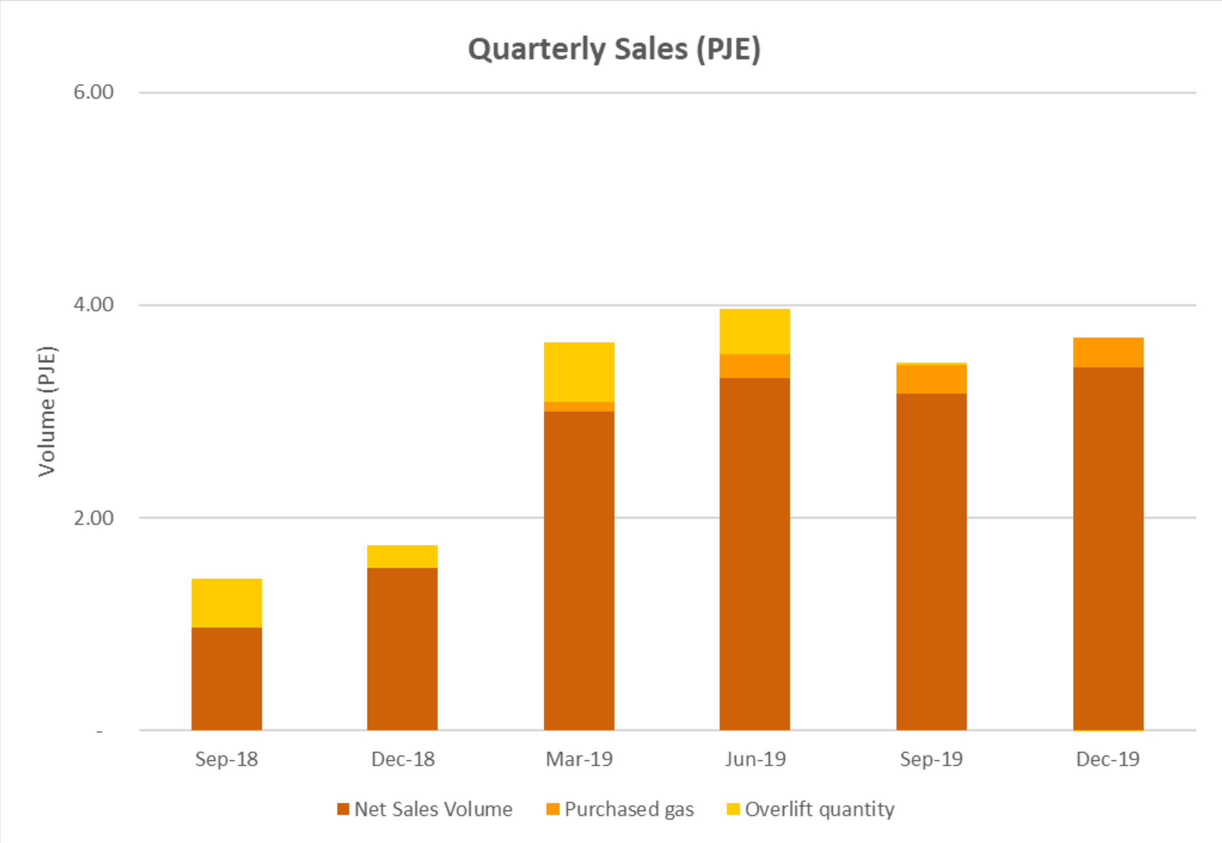

Figure 1: Quarterly sales volumes (CTP equity share)

Sales volumes increased 6.7% from the preceding June quarter to 3.7 PJE (includes the sale of 0.3 PJ of purchased gas). This compares to 3.5 PJE in the preceding September 2019 quarter (included 0.3 PJ of purchased gas). The increase in sales volumes was largely due to improved availability of the Northern Gas Pipeline, which was subject to an extended shutdown in the September quarter.

Total Sales Revenue

		2019/20		2018/19	2019/20	2018/19
Product	**Unit**	**Q2**	**Q1**	**Q2**	**YTD**	**YTD**
Gas	$'000	16,487	15,196	8,831	31,684	15,695
Crude and Condensate	$'000	2,059	1,970	1,619	4,029	4,327
Total Sales Revenue	**$'000**	**18,546**	**17,166**	**10,450**	**35,713**	**20,022**

Total sales revenue in the December quarter was $18.5 million, up 7.5% from $17.2 million in the September 2019 quarter. The increased revenues reflect the 6.7% increase in volumes due to improved reliability of the Northern Gas Pipeline and a slightly higher revenue per unit of $5.03/GJE due to the incremental sales supplying higher-priced contracts in the portfolio.

Year to date sales revenues are 78% higher than the corresponding period in 2018 due to access to new gas markets from January 2019 when the Northern Gas Pipeline opened.

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

(CTP - 50% interest (and Operator), Macquarie Mereenie Pty Ltd - 50% interest).

At the end of the quarter, Mereenie field production capacity was 44 TJ/d (100% JV).

Mereenie field production over the quarter was consistent with the previous quarter, averaging 40.7 TJ/d (100% JV) (September qtr: 40.1 TJ/d), reflecting improved availability of the Northern Gas Pipeline, in-field optimisation and well interventions which served to partially offset natural field decline. The data acquisition and capacity-add programme continued in the quarter, which will provide information necessary to guide ongoing optimisation activities.

A campaign of targeted recompletions is being planned for execution in the 2nd half of CY2020. Timing for future production wells to optimise Mereenie field production capacity is also under consideration for later this year.

The Company continues to progress optimisation opportunities in the field and in the plant to mitigate the natural decline in production from existing Mereenie wells.

Palm Valley (OL3) - Northern Territory

(CTP - 100% interest)

Palm Valley production increased 29% from the September quarter, averaging 12.1 TJ/d compared to the 9.4 TJ/d achieved in the September quarter. The increase can primarily be attributed to improved availability of the Northern Gas Pipeline and more stable customer demand in the quarter.

The new PV13 well, which was commissioned in May 2019, continued to produce at a plateau rate of 7.0 TJ/d which has exceeded expectations. Given the success of PV13 so far, planning continues for another horizontal production well as part of the PV Deep exploration drilling in Palm Valley later this year.

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

(CTP - 100% interest)

Average gas production of 3.3 TJ/d from the Dingo Gas Field was consistent with the previous quarter average of 3.3 TJ/day. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions paid annually to Central in January for the preceding calendar year. The Dingo Gas Field supplies gas to the Owen Springs Power Station.

DEVELOPMENT ACTIVITIES

Range gas project (ATP 2031) - Queensland

(CTP - 50% interest, Incitec Pivot Queensland Gas Pty Ltd ("Incitec") - 50% interest)

The four successful exploration wells drilled earlier in the year exceeded expectations, with higher than anticipated 2C contingent gas resources of 270 Petajoules (PJ) (135 PJ Central share) booked in ATP 2031 in Queensland's coal seam gas rich Surat Basin in August 2019. The 2C "development pending" classification is the highest category of contingent resource, requiring only satisfaction of final investment decision (FID) milestones such as development plans, access to infrastructure and offtake agreements for conversion to certified 2P gas reserves. The Range gas project is at the doorstep of the east coast gas market and could nearly double Central's reserve base within 15 months and has the potential to almost double Central's production by 2022.

During the December quarter, Central and joint venture partner, Incitec continued to progress a three well appraisal pilot program designed to produce gas and water to a local flare and above-ground tank. Evaluation of tenders continued for the drilling program which is now planned for Q2CY2020.

Parallel to the pilot program planning, the joint venture is progressing towards a FID on an accelerated basis for what is likely to be a substantial CSG development. These pre-FID activities include conducting environmental studies, securing approvals, undertaking engineering studies, selecting equipment and ordering long-lead items. First gas sales from the Range gas project are targeted for 2022.

It is anticipated that completion of the pre-FID activities and a successful appraisal pilot will lead to a conversion of 2C contingent resource to 2P certified reserves.

The Range gas project is situated in Queensland's Surat Basin, a geological province whose CSG reserves have attracted billions of dollars of investment over the last decade and now supplies gas to both the domestic market and international consumers through Gladstone's LNG facilities. There are a number of CSG wells in adjacent blocks and areas within the Walloons coal fairway in the same depth band as the Range gas project which have been successfully developed for production. The permit area covers 77km^2 and is located approximately 28km north-west of the town of Miles which lies half way between the Wooleebee Creek and Bellevue CSG developments.

Gas production from this permit will be sold to the east coast domestic gas market.

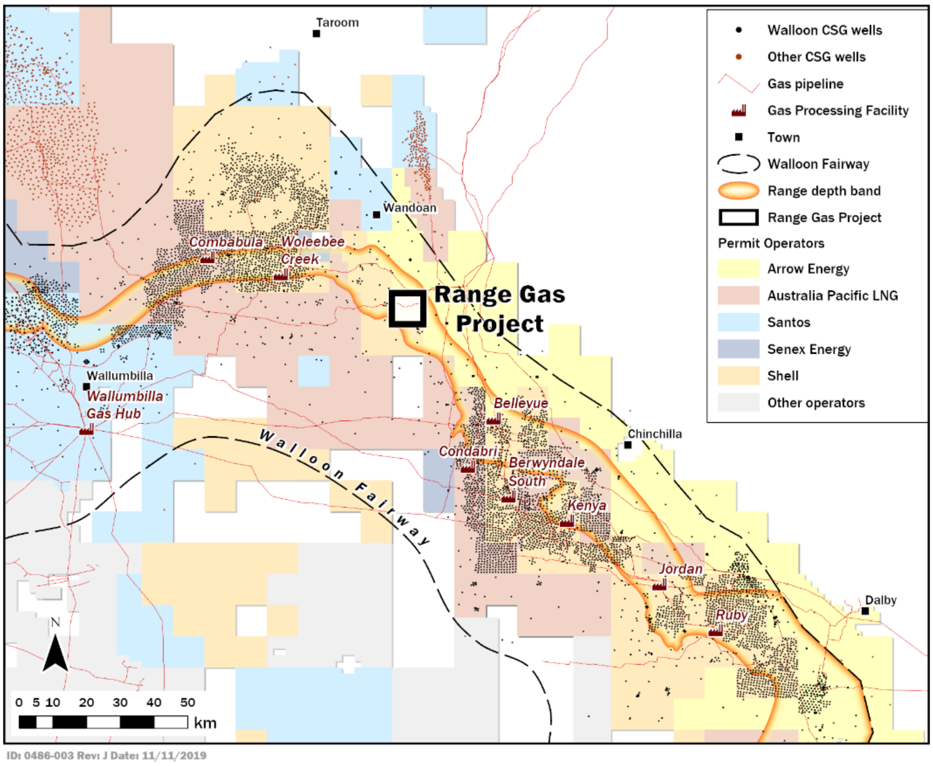

Figure 2: Location map of the Range gas project showing proximity to existing infrastructure and producing gas fields

The exploration and appraisal program is being undertaken through a 50:50 joint venture arrangement with Incitec which has carried Central's 50% share of the first $20 million of exploration and appraisal costs up to 31 December 2019. In January 2020, subsequent to the end of the quarter, Central received $7.7 million from IPL, being the balance of the uncommitted 'carry'. All future project costs, including pilot and pre-FID activity will be funded 50/50 under the joint venture arrangements.

EXPLORATION ACTIVITIES

Dukas-1 (EP112) – Northern Territory

(CTP – 30%, Santos (and Operator) – 70% (farm-in in progress))

Dukas-1 is located approximately 175km south west of Alice Springs (Figure 3) and the prospect has multi-TCF gas potential (30% net to Central, subject to the Farmout Agreement).

The Dukas-1 exploration had a proposed total depth of 3,850m and targeted a large regional high optimally located to receive charge from an interpreted Neoproterozoic depocenter. Dukas-1 reached a depth of 3,704m in August when it encountered formation pressures much higher than predicted in association with a combination of hydrocarbon and inert gasses. Santos (as operator) subsequently assessed that the technical requirements to drill forward were in in excess of the capabilities of the rig and surface equipment, with drilling activity suspended and the rig released.

The primary reservoir objective is the Heavitree Quartzite/fractured basement is yet to be penetrated.

Central is exploring options and opportunities to accelerate completion of the Dukas-1 well within the contractual framework of the EP112 Joint Venture agreement with Santos. While a forward plan for Dukas-1 is subject to JV approval, Central would like to complete this important and potentially market changing exploration well as soon as practicable (potentially in the first half of 2021). A forward plan for Dukas-1 remains under active discussion within the JV and will be announced as soon as it has been formally agreed by the parties.

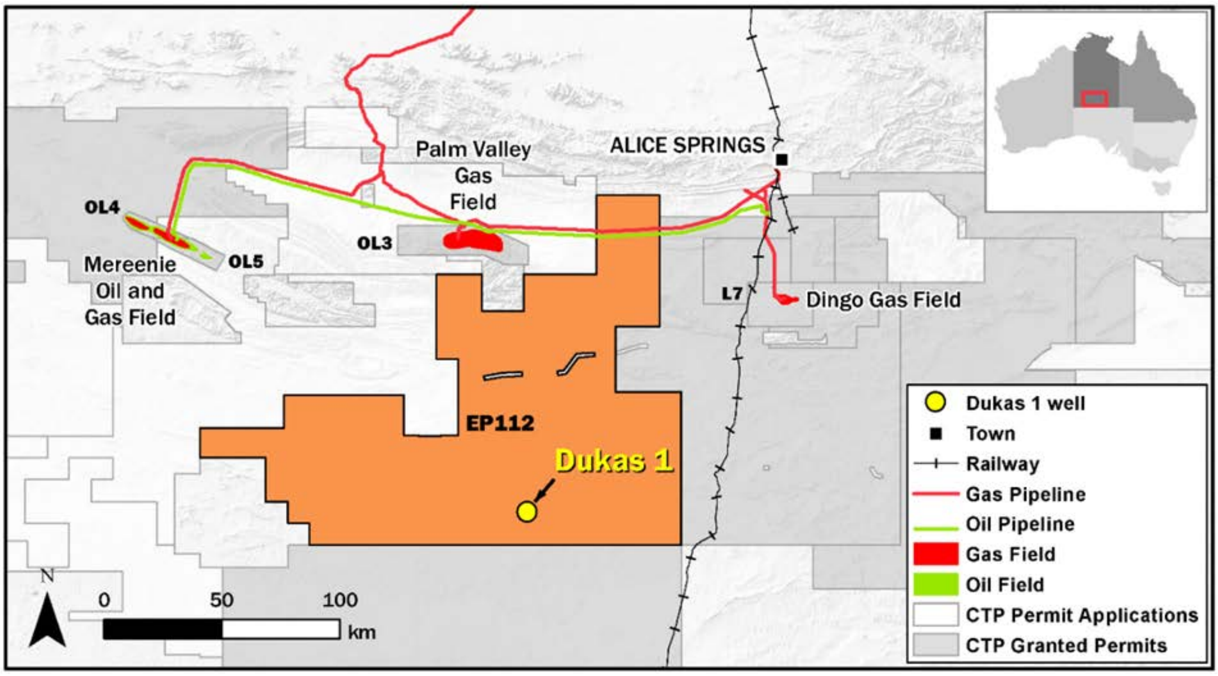

Figure 3: Location map of Dukas-1 and EP112

Upon completion of the Stage 3 farmout, Central's participating interests will be as presented in Table 1 below.

Table 1: Summary of Central's interests in the Southern Amadeus Joint Venture

Southern Amadeus Area	Total Central Participating Interest after completion of Stage 3 Farmout to Santos
EP 82 (excluding EP 82 Sub-Blocks) **	60%
EP 105**	60%
EP 106 * & **	60%
EP 112 **	30%
EP 125 **	30%
EP 115 (North Mereenie Block) **	60%

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

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

CY2020 Exploration Programme

The CY2020 exploration programme announced in October is an exciting and potentially Company changing near-term activity for Central that consists of five high-graded drillable targets and two appraisal tests. These exploration targets range from low to moderate-risk opportunities with compelling investment justifications, including rapid commercialisation, attractive brownfield economics, proximity to existing infrastructure, and drill-ready in CY2020. Key attributes include:

a) Large prospective resources, totalling 505PJ of gas and 29mmboe of oil (unrisked mean prospective resources)

b) Lower risk exploration and appraisal near existing production;

c) Capable of completion in CY2020;

d) Able to be quickly monetised through existing access to markets; and

e) Higher margin targets utilising existing production facilities (brownfield economics).

The CY2020 exploration programme targets natural fractures within conventional formations. No artificial stimulation (hydraulic fracturing) is proposed for this exploration programme.

Work to progress the CY2020 exploration programme continued during the December quarter, finalising well designs and progressing the approvals processes required for exploration in the Northern Territory. To date, applications for Aboriginal Areas Protection Authority (AAPA) Certificates for the Dingo, Orange, Palm Valley-12 and Mamlambo exploration wells and the West Mereenie development wells have been lodged, and AAPA's assessment process is underway. Ecological assessments were also undertaken at all sites in December, with no significant ecological constraints identified at this time. Work on the Environmental Management Plans for NT Government approval of the exploration wells continues to progress.

The CY2020 exploration program is estimated to have a total cost of circa $50 million and an aggregated best estimate (P50) prospective resource of up to 321 PJ of gas (205 PJ risked mean) and 24 mmbbl of oil (9.5 mmbbl risked mean).

The estimated aggregate prospective resources contained within the prospects (net to Central) are:

Table 2: Estimated aggregate Prospective Resources (see Cautionary Statement below)

	Unit	Best estimate (P50)	Mean	Risked Mean
Gas	Petajoules	321	505	205
Oil	Million barrels	24	29	9.5

Table 3: Summary of exploration prospects and volumes (see Cautionary Statement below)

Lead / Prospect	Target	Depth (mMD)	Permit	Permit Interest	Low Estimate P90 Recoverable (PJ)	Best Estimate P50 Recoverable (PJ)	High Estimate P10 Recoverable (PJ)	Mean Recoverable (PJ)
Dingo Deep	Pioneer	3600	L7	100%	13	41	135	63
Orange-3	Arumbera	2800	EP82(DSA)	100%	17	81	296	131
	Pioneer	3500	EP82(DSA)	100%	23	84	275	129
Palm Valley Deep	Arumbera	3600	OL3	100%	17	80	299	131
Palm Valley West	Pacoota	1900	OL3	100%	7	35	114	51
Aggregate gas						321		505
Oil prospects					(mmbbl)	(mmbbl)	(mmbbl)	(mmbbl)
Mamlambo	Pacoota	1500	L6	100%	7	24	60	29

Contingent and prospective resources

Volumes presented in tables 2, 3 and 4 represent the unrisked recoverable volumes derived from montecarlo probabilistic volumetric analysis for each prospect. Inputs required for these analyses have been derived from offset wells and fields relevant to each play and field. Recovery factors used have been derived from analogous field production data.

The Prospective Resources were first reported to ASX on 11 October 2019 and the Contingent Resources are as reported in the 30 June 2019 Annual Report. Central confirms that it is not aware of any new information or data that materially affects the information included in those announcements and all material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Risked recoverable volumes have been derived by using the geological chance of success for each individual prospect and multiplying the mean recoverable volume and aggregating the result.

Cautionary Statement: the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

In addition to the exploration wells above, the 2020 exploration programme also includes two appraisal tests that could provide a potential pathway for converting 2C contingent resources of 54 PJ (Central share) to reserves within the Mereenie Stairway formations. Optimal lateral drilling and completion techniques are currently under review, including horizontal drilling with coil tubing and radial jetting.

Table 4: Summary of Stairway Appraisal gas opportunity at Mereenie

Appraisal target	Target	Permit	Permit Interest	2C Contingent (PJ)	
Mereenie Stairway	Stairway	OL4/5	50%	54	(Net to Central)

Farm-out process commenced

Central plans to fully fund the CY2020 exploration programme through a formal farmout process. Central's current operating assets at Mereenie, Palm Valley, and Dingo have all benefitted from recent access to the east coast gas market via the NGP. Central believes this catalyst has generated an uplift in asset value that could be released efficiently through a sell-down. The key parameters for such divestment are anticipated to include:

- Central to retain a majority interest;
- Central to remain as operator; and
- Attract a fully aligned JV partner with financial and technical capacity.

Subsequent to the end of the quarter, Central appointed Flagstaff Partners Pty Ltd as its advisor for the farm-out of the CY2020 programme and associated operating assets (Mereenie, Palm Valley, Dingo and Surprise).

The farm-out process is underway with encouraging interest being shown by interested parties.

Longer Term Exploration Strategies

The Amadeus Basin is an extensive underexplored basin with five working hydrocarbon systems demonstrating proven oil and gas production. Central has identified many less-mature, but potentially company-changing, oil and gas prospects throughout the basin. Work has been progressing on a play-based basin mapping that will enable the Company to mature these opportunities into drillable prospects with much better technical understanding and focus. The play-based mapping of these prospects, including potential Dukas "look-a-likes", will allow these exploration targets to be graded and prioritised. Central will present the results of this analysis and longer-term exploration strategies once finalised later in CY2020.

Ooraminna Field (RL3 and RL4) – Northern Territory

(CTP - 100% interest)

Based on the updated portfolio review and analysis, the Ooraminna-3 well was not as compelling on a risk-return basis as the competing CY2020 exploration targets above. The DPIR have agreed in principal to the deferral of the Ooraminna 3 well and a variation of the work program for RL 3 and RL 4 was submitted to the DPIR on 12 December 2019 and is awaiting a formal decision.

Amadeus Basin (excludes EP 115 North Mereenie Block) – Northern Territory

*(CTP and other interests – see "INTERESTS IN PETROLEUM PERMITS AND LICENCES TABLE" below)**.***

Central began initial planning for the Year 3 permit commitment of 500km of seismic acquisition in EP115 during the quarter. The final layout has yet to be agreed on, however, the targets will include leads at the Ordovician (Stairway and Pacoota Sandstone), Arumbera, Pioneer, Areyonga and Heavitree/ basement horizons. The result of the Dukas-1 and Mamlambo-1 wells will influence the location of the upcoming seismic program which was due to be acquired before December 2019. An application for permit suspension was submitted and granted to facilitate a more informed seismic program whilst still meeting schedules necessary to keep the permit in good standing.

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

(CTP - 100% interest)

Central is currently conducting Year 1 permit obligations of geology and geophysical studies focusing on the Ethabuka structure. Ethabuka-1 was drilled in 1973 and tested gas at ~0.2 mmscfd from the Coolibah Formation, the well being abandoned prematurely due to mechanical difficulties and weather. As such, the large Ethabuka anticline remains to be fully tested at multiple levels. Work also continues on the development of a large hydrothermal dolomite play in the blocks.

INTERESTS IN PETROLEUM PERMITS AND LICENCES AT 31 DECEMBER 2019

Petroleum Permits and Licences Granted

Tenement	Location	Operator	CTP Consolidated Entity		Other JV Participants	
			Registered Legal Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks) [1]	Amadeus Basin NT	Santos	60	60	Santos QNT Pty Ltd ("Santos")	40
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 105 [1]	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106 [3]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 112 [1]	Amadeus Basin NT	Santos	30	30	Santos	70
EP 115 (excl. EP 115 North Mereenie Block[6])	Amadeus Basin NT	Central	100	100		
EP 115 North Mereenie Block [6]	Amadeus Basin NT	Santos (transitioning to Central)	60	100	Santos	0
EP 125	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	100	100		
OL 4 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie Pty Ltd ("Macquarie Mereenie")	50
OL 5 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	100	100		
RL 3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna)	Amadeus Basin NT	Central	100	100		
ATP 909	Georgina Basin QLD	Central	100	100		
ATP 911	Georgina Basin QLD	Central	100	100		
ATP 912	Georgina Basin QLD	Central	100	100		
ATP 2031	Surat Basin QLD	Central	50	50	Incitec Pivot Queensland Gas Pty Ltd	50

Petroleum Permits and Licences under Application

Tenement	Location	Operator	CTP Consolidated Entity		Other JV Participants	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111 [2]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124 [2 & 5]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 129	Wiso Basin NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 131 [4]	Pedirka Basin NT	Central	100	0		
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 [5]	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		
EPA 296	Wiso Basin NT	Central	100	100		

Pipeline Licences

Pipeline Licence	Location	Operator	CTP Consolidated Entity		Other JV Participants	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
PL 30	Amadeus Basin NT	Central	100	100		

Notes:

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

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

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

4 *This exploration permit application has been disposed with legal transfer to occur following the grant of the exploration permit.*

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

6 *On 18 December 2019 Central received notice from Santos of Santos' decision to withdraw from the EP 115 North Mereenie Block.*

HEALTH, SAFETY AND ENVIRONMENT

There were no MTIs or LTIs recorded during the quarter.

There were no reportable environmental incidents during the quarter.

The Field Environmental Management Plans (FEMP) for the Dingo and Surprise Operations are due for renewal. With operations at the Surprise field remaining suspended, the NT Department of Environment and Natural Resources (DENR) agreed that Surprise could be combined with Dingo for the EMP update. A draft combined FEMP was submitted to DENR in December. Following DENR's review, the FEMP is now being finalised and is expected to be submitted in late January 2020.

CORPORATE

Cash Position

The Group held cash of $14.9 million at the end of the quarter down from $16.5 million at the end of the September 2019 quarter.

The net cash inflow from operations before exploration, tax and financing costs was $6.3 million.

The net cash inflow from operations for the quarter was $3.9 million, after payment of $0.4 million of exploration costs and $1.4 million of interest payments. This was down from $4.4 million in the September 2019 quarter, with the decrease being largely attributable to one-off tax-related payments to the ATO of $0.6 million.

Cash receipts from customers during the December 2019 quarter were $15.7 million (no cash was received for the 437 TJ of pre-sold gas delivered during the quarter).

Cash production costs were $8.0 million for the current quarter inclusive of gas purchases of $1.5 million.

Cash expenditure on capital projects (non-exploration) amounted to $0.7 million, which included $0.1 million on Palm Valley facilities (completion of PV13 tie-in and plant upgrades) and $0.2 million on Mereenie upgrades.

Interest charges amounting to $1.4 million were lower than the previous quarter, reflecting the benefit of accelerated debt repayments and softening interest rates.

In addition to delivery of 437 TJ of gas under the Macquarie pre-sale agreement, principal repayments under Macquarie debt facilities amounting to $4.75 million were made during the quarter. The total outstanding balance of the Macquarie facilities was $72.8M at quarter end.

Central's accelerated debt repayment schedule has resulted in total debt principal repayments of $21.5 million in CY2019. Prior to the NGP commissioning in January 2019, Central's debt was $94 million. Central's operating cashflows and reduced debt is expected to bring financing / balance sheet flexibility in 2020.

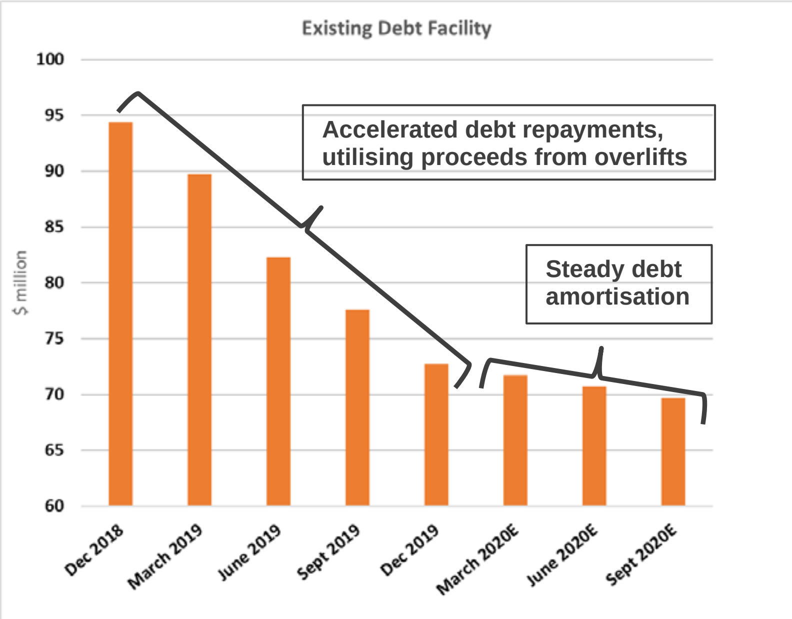

Figure 4: Outstanding debt balances

Debt Refinancing

Central's existing finance facility matures on 30 September 2020 and the Company has been progressing discussions with potential senior lenders. Refinancing activity is being undertaken with a view to the medium term capital requirements of the Group, including a refinance package that will provide flexibility to accommodate Central's farm-out process and the Range Gas Project FID.

Gas Marketing

In December, Central announced a new gas sales agreement (GSA) under which the Mereenie Joint Venture (MJV) (Central interest 50%) will supply up to 21.9 PJ of 'firm' and 'as-available' gas to AGL Energy over three years from 1 January 2020. Whilst Central has a 50% contractual obligation for gas supply under the GSA, Central expects to receive the benefit of the majority of the revenue during the first two contract years under portfolio balancing arrangements with its MJV partner.

The new GSA is shared jointly with Central's MJV partner and therefore only partially replaces Central's maturing Incitec supply contract. Central continues to market remaining firm capacity to potential customers to top-up its portfolio. With the transition to the gas contracting arrangements progressing in early 2020, Central's share of gas sales in the next (March 2020) quarter are expected to be lower than in the December quarter.

To support the AGL GSA and the ongoing investment necessary to optimise Mereenie field production, the MJV participants agreed a package of commercial arrangements for natural gas delivered from the jointly-owned Mereenie Field. The arrangements accomplish two main outcomes:

1. Portfolio balancing: Gas supplied under the AGL GSA will be re-allocated between Central and Macquarie Mereenie Pty Limited with the goal of equalising monthly sales volumes from the Mereenie field. Under this balancing mechanism, Central is expected to be re-allocated the majority of gas supplied under the AGL Energy GSA during the first two contract years;
2. Overlift return: a portion of Central's current overlift imbalance is to be gradually returned over a period consistent with the term of the AGL Energy GSA. The overlift return is structured through a 2.4PJ gas purchase agreement spread over the three years from 1 January 2020.

As a package, the new commercial arrangements provide MJV alignment for ongoing investment in field production capacity.

Issued Securities of the Company

At 31 December 2019 the Company had 723,057,206 ordinary shares on issue, 23,988,051 share rights expiring on various dates and 40,651,116 unlisted options exercisable at various prices on various dates.

Movement in securities during the quarter:

- 647,770 ordinary shares were issued as a consequence of share rights exercised by employees in accordance with the Company's Employee Rights Plan;
- 1,837,109 share rights were granted to employees in accordance with the Company's Employee Rights Plan and 2,245,532 shares rights were cancelled; and
- 5,105,000 unlisted options were granted to executives in accordance with the Executive Share Option Plan (as an alternative to their participation in the Company's Long Term Incentive Plan).

Leon Devaney

Chief Executive Officer and MD
30 January 2020

General Legal Disclaimer

As new information comes to hand from data processing and new drilling and seismic information, preliminary results may be modified. Resources estimates, assessments of exploration results and other opinions expressed by the Company in this announcement or report have not been reviewed by any relevant joint venture partners, therefore those resource estimates, assessments of exploration results and opinions represent the views of the Company only. Exploration programmes which may be referred to in this announcement or report may not have been approved by relevant Joint Venture partners in whole or in part and accordingly constitute a proposal only unless and until approved.

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+Rule 5.5

Appendix 5B

Mining exploration entity and oil and gas exploration entity quarterly report

Introduced 01/07/96 Origin Appendix 8 Amended 01/07/97, 01/07/98, 30/09/01, 01/06/10, 17/12/10, 01/05/13, 01/09/16

Name of entity

CENTRAL PETROLEUM LIMITED

ABN	**Quarter ended ("current quarter")**
72 083 254 308	31 DECEMBER 2019

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date (6 months) $A'000**
1.	**Cash flows from operating activities**		
1.1	Receipts from customers		
	- Product receipts	15,720	32,168
	- Take or pay receipts	—	—
1.2	Payments for		
	(a) exploration & evaluation	(447)	(1,257)
	(b) development	–	–
	(c) production and gas purchases	(7,992)	(16,577)
	(d) staff costs	(1,165)	(2,022)
	(e) administration and corporate costs (net of recoveries)	(225)	(662)
1.3	Dividends received (see note 3)	–	–
1.4	Interest received	38	97
1.5	Interest and other costs of finance paid	(1,371)	(2,821)
1.6	Income taxes paid	–	–
1.7	Research and development related tax refunds	(634)	(634)
1.8	Other	–	–
1.9	**Net cash from / (used in) operating activities**	**3,924**	**8,292**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire:		
	(a) property, plant and equipment	(680)	(1,477)
	(b) tenements (see item 10)	–	–
	(c) investments	–	–
	(d) other non-current assets – Security Bonds	–	–
2.2	Proceeds from the disposal of:		
	(a) property, plant and equipment	44	54
	(b) tenements and applications (see item 10 for tenements)	–	–
	(c) investments	–	–
	(d) other non-current assets – redemption of security bonds	–	–
2.3	Cash flows from loans to other entities	–	–
2.4	Dividends received (see note 3)	–	–
2.5	Other (refunded deposit to Joint Venture partner on withdrawal from Joint Venture)	–	–
2.6	**Net cash from / (used in) investing activities**	**(636)**	**(1,423)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of shares	–	–
3.2	Proceeds from issue of convertible notes	–	–
3.3	Proceeds from exercise of share options	–	–
3.4	Transaction costs related to issues of shares, convertible notes or options	(10)	(10)
3.5	Proceeds from borrowings	–	–
3.6	Repayment of borrowings	(4,752)	(9,501)
3.7	Transaction costs related to loans and borrowings	–	–
3.8	Dividends paid	–	–
3.9	Other - Principal elements of lease payments	(118)	(300)
3.10	**Net cash from / (used in) financing activities**	**(4,880)**	**(9,811)**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	16,456	17,806
4.2	Net cash from / (used in) operating activities (item 1.9 above)	3,924	8,292
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(636)	(1,423)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(4,880)	(9,811)
4.5	Effect of movement in exchange rates on cash held	–	–
4.6	**Cash and cash equivalents at end of period**	**14,864**	**14,864**

5.	**Reconciliation of cash and cash equivalents** at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	**Current quarter $A'000**	**Previous quarter $A'000**
5.1	Bank balances[1]	14,863	16,455
5.2	Call deposits	–	–
5.3	Bank overdrafts	–	–
5.4	Other (Cash on hand)	1	1
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**14,864**	**16,456**

[1] *Includes share of Joint Venture bank accounts, and cash held with Macquarie Bank Limited (Current Quarter $2,307,487; Previous Quarter $2,752,511) to be used for allowable purposes under the Facility Agreement.*

6.	**Payments to directors of the entity and their associates**	**Current quarter $A'000**
6.1	Aggregate amount of payments to these parties included in item 1.2	272
6.2	Aggregate amount of cash flow from loans to these parties included in item 2.3	–

6.3 Include below any explanation necessary to understand the transactions included in items 6.1 and 6.2

Includes Salaries, Directors fees and Superannuation contributions

7.	Payments to related entities of the entity and their associates	Current quarter $A'000
7.1	Aggregate amount of payments to these parties included in item 1.2	–
7.2	Aggregate amount of cash flow from loans to these parties included in item 2.3	–

7.3 Include below any explanation necessary to understand the transactions included in items 7.1 and 7.2

8.	Financing facilities available *Add notes as necessary for an understanding of the position*	Total facility amount at quarter end[2] $A'000	Amount drawn at quarter end $A'000
8.1	Loan facilities	72,809	72,809
8.2	Credit standby arrangements	–	–
8.3	Other (please specify)	–	–

8.4 Include below a description of each facility above, including the lender, interest rate and whether it is secured or unsecured. If any additional facilities have been entered into or are proposed to be entered into after quarter end, include details of those facilities as well.

8.1 - Represents the Macquarie Bank Facility which is a secured 5 year partially amortising term loan maturing 30 September 2020 with quarterly principal and interest repayments. The weighted average interest rate at end of the current quarter was 6.44% (floating interest rate).

[2] *Amortised remaining Facility limit.*

9.	Estimated cash outflows for next quarter[3]	$A'000
9.1	Exploration and evaluation	(2,865)
9.2	Development	–
9.3	Production and gas purchases	(10,010)
9.4	Staff costs (net of recoveries)	(961)
9.5	Administration and corporate costs (net of recoveries)	(361)
9.6	Other	
	- Payments for property, plant & equipment	(1,567)
	- Interest and debt repayments	(2,469)
9.7	**Total estimated cash outflows**	**(18,233)**

[3] *Outflows only, does not reflect proceeds from product sales.*

10.	**Changes in tenements (items 2.1(b) and 2.2(b) above)**	**Tenement reference and location**	**Nature of interest**	**Interest at beginning of quarter**	**Interest at end of quarter**
10.1	Interests in mining tenements and petroleum tenements lapsed, relinquished or reduced	EP93 Pedirka Basin NT EP97 Pedirka Basin NT EP107 Pedirka Basin NT	Petroleum Exploration Permit Petroleum Exploration Permit Petroleum Exploration Permit	100% 100% 100%	Nil Nil Nil
10.2	Interests in mining tenements and petroleum tenements acquired or increased				

Compliance statement

1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.

2 This statement gives a true and fair view of the matters disclosed.

Sign here: .... Date: 30 January 2020
(Director/Company secretary)

Print name: ....JOSEPH MORFEA...

Notes

1. The quarterly report provides a basis for informing the market how the entity's activities have been financed for the past quarter and the effect on its cash position. An entity that wishes to disclose additional information is encouraged to do so, in a note or notes included in or attached to this report.
2. If this quarterly report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, AASB 6: Exploration for and Evaluation of Mineral Resources and AASB 107: Statement of Cash Flows apply to this report. If this quarterly report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.