CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

ASX:CTP

Activities Report and ASX Appendix 5B

REVIEW OF OPERATIONS FOR THE QUARTER ENDED 31 DECEMBER 2025

Highlights

- **Letter of Intent secured for long term gas supply,** which, subject to execution of a binding Gas Sale Agreement, will see Central supply up to 25.5 PJ (Central Share) of gas through to the end of 2034 and underwrite the drilling of four new wells at Mereenie and Palm Valley later this year.
- **New Gas Sales Agreement:** Central secured a new Gas Sale Agreement to a NT mine for the supply of 1.3 PJ (Central share) of gas over two years from 31 December 2025.
- **Strategic expansion into highly prospective Otway and Cooper Basin exploration permits:** Central agreed to acquire an interest in an exploration permit located in the onshore Otway Basin of Victoria and 24 Cooper Basin retention leases and one exploration permit in South Australia, with at least three new exploration wells targeting oil and gas expected to be drilled in the next 18 months.
- **Conditional sale of sub-salt exploration permits**: Central entered into a conditional agreement to sell two sub-salt exploration permits in the NT to UK-listed Georgina Energy Plc (Georgina) (LSE: GEX) in exchange for a 25% equity interest in Georgina. If the transaction completes, drilling of a sub-salt appraisal well at Mt Kitty is expected in mid-2027, targeting helium and hydrocarbons.
- **Gas sales prices:** the average realised delivered gas price across the portfolio was $9.59 / GJ for the December quarter, 30% higher than the same quarter last year, but 2% lower than the September quarter due to fluctuations in the mix of contract volumes.
- **Sales volumes** of 1.1 PJe (Petajoule equivalent) were 2% lower than the September quarter, resulting from oil offtake constraints for much of the quarter.
- **Sales revenue** of $10.4m for the December quarter was 7% lower than the previous quarter due primarily to oil sale constraints and the associated lower gas sales volumes and sales prices.
- **Cash balance** at the end of the quarter was $29.4m, up from $26.7m at 30 September. Key cash flows included:
  - Net operating inflows of $4.5m before net interest and exploration costs;
  - CAPEX of $1.0m and $0.3m toward the Otway and Cooper Basin permit acquisitions; and
  - Exploration related expenditures of $0.5m.
- **Net cash** was $5.3 million at 31 December, including $2.5 million of funds held as security for the loan facility. The December quarter interest payment of $0.7m was capitalised into the loan balance.
- **Share buy-back:** opened an on-market share buy-back program, Central's first shareholder returns. 799,500 shares were purchased on-market in December, and a further 1,385,630 acquired in January 2026.

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Commercial

In the December quarter, Central announced several significant strategic transactions and agreements which elevate Central's position in Australia's evolving energy landscape. When these transactions and agreements are ultimately completed as planned, Central will have:

- executed a Government-backed gas offtake that provides secure revenues and cash flows until 2034 and underwrites an increase in production through the drilling of four new wells in the Amadeus Basin, with drilling scheduled to commence in mid-2026;
- expanded its exploration footprint into two of Australia's proven onshore basins with lower-cost, near-term exploration drilling opportunities which provide significant potential for future growth and close proximity to the buoyant east coast gas market; and
- restructured its sub-salt exploration position in the Southern Amadeus Basin, retaining significant upside associated with sub-salt helium exploration and stimulating drilling activity which has stalled in recent years.

As a result of these initiatives, the next 18 months could see Central participating in up to eight new wells, including lower-risk development and appraisal wells to boost near-term production and higher risk and higher-impact exploration wells across three basins targeting material new gas, oil and helium resources.

LETTER OF INTENT FOR NEW LONG TERM GAS SUPPLY

Central and its partners in the Mereenie and Palm Valley joint ventures have entered into a binding letter of intent with the Northern Territory's Power & Water Corporation which included 'in-principle' terms for long-term, firm gas supply under term sheets covering uncontracted firm gas production at market pricing from the Mereenie and Palm Valley fields of up to 25.5 PJ (Central share) through to the end of 2034, which includes additional production from four new wells.

The gas supply term sheets are non-binding and conditional, requiring final internal approvals from all parties. The parties remain on track to formalise and execute binding Gas Sale Agreements (GSAs) by 20 February 2026.

The intended supply arrangements are designed to quickly deliver significant new gas volumes to the Northern Territory, while also enhancing gas supply security for customers throughout the region. Preparations for four new wells (two at Mereenie and two at Palm Valley) are already well-advanced, with key approvals in place or underway, orders placed for long lead items, drilling rig contracting in progress and civil works commenced.

By committing to early works in advance of FID, the wells can be accelerated, allowing drilling to commence in mid-2026. It is expected that the additional gas production can be quickly supplied to the market after drilling, as the wells will utilise available production capacity at the existing Mereenie and Palm Valley gas fields.

The proposed GSAs would not only underwrite the drilling program and additional production volumes but also provide Central with a reliable government-backed income stream well into the next decade without ongoing exposure to the Northern Gas Pipeline's operations.

NEW GAS SUPPLY AGREEMENT

In October, Central announced a new Gas Supply Agreement (GSA) to supply 1.3 PJ (Central share) of gas to McArthur River Mining over two years from 31 December 2025. The new GSA is for firm supply at a fixed price, with take-or-pay provisions, providing increased cash flow certainty. This GSA secures contracts for Central's forecast firm gas production from existing wells through to the end of 2027.

EXPANDED EXPLORATION FOOTPRINT – COOPER AND OTWAY BASINS

Central has substantially expanded its exploration portfolio to include two of Australia's proven onshore basins with lower-cost, near-term drilling opportunities that provide significant growth potential and an opportunity to benefit from tight supply in the east and south-east gas markets.

Central has acquired a:

- 20% interest in Victorian exploration permit PEP 169 in the onshore Otway Basin where seismic surveys have identified, among other substantial conventional prospects, the highly prospective, amplitude-supported, Enterprise North gas target. The Enterprise North exploration well (to become a production well on success) is scheduled to be drilled in 2H 2026; and
- 49% interest in 24 South Australian Retention Leases (PRLs) and exploration permit PEL 677 in the prolific Cooper Basin, where extensive seismic surveys have identified, among other substantial conventional oil and gas targets, several priority oil leads, with two to three exploration wells (to become production wells on success) scheduled to be drilled in early 2027.

As consideration for the acquisition, Central has paid a total of $9.2 million in January 2026, plus $1.5m of back costs. Contingent future payments consist of a $3.9m success payment conditional on commercial success from the planned exploration well at Enterprise North and a 5% royalty payable on future production from Central's 49% interest in the Cooper acreage.

The permits will be operated by ADZ Energy, a low-cost, onshore explorer with strong technical expertise.

Otway Basin – PEP 169 (Central: 20% interest)

The Enterprise North prospect is considered one of the most prospective onshore gas targets in Australia, immediately to the north of the prolific Enterprise gas field, discovered in 2020.

Enterprise North is ideally located onshore within the high value Victorian gas market. Land access has been secured close to existing pipelines and three existing processing facilities (Iona, Otway and Athena Gas Plants). In addition, the exploration well has been designed so that it will become a production well in a success scenario. Consequently, it is expected that gas sales can be initiated quickly and with only nominal wellhead facilities and other capex required. In the longer term, there are a series of other gas targets already identified in the permit, and opportunities to utilise the reservoir for gas storage following depletion will be considered.

The Enterprise North exploration well will target natural gas in the Waarre Formation at an estimated depth of approximately 2,000 m. The well is planned to be drilled in the southern part of PEP 169, approximately 8.5 km southwest of the Iona Gas Field and 2.5 km north of the producing offshore Enterprise gas field.

Central estimates there to be up to 79 Bcf of gas in place in the Waarre C formation at Enterprise North (Central 20% share: ~16 Bcf):

Enterprise North (PEL169)	100% JV		Central 20% interest	
	Gas in place[1] (Bcf)	Prospective Resource[1] (Bcf)	Gas in place[1] (Bcf)	Prospective Resource[1] (Bcf)
High estimate	78.9	51.3	**15.8**	**10.3**
Best estimate	43.9	28.6	**8.8**	**5.7**
Low estimate	5.4	3.5	**1.1**	**0.7**

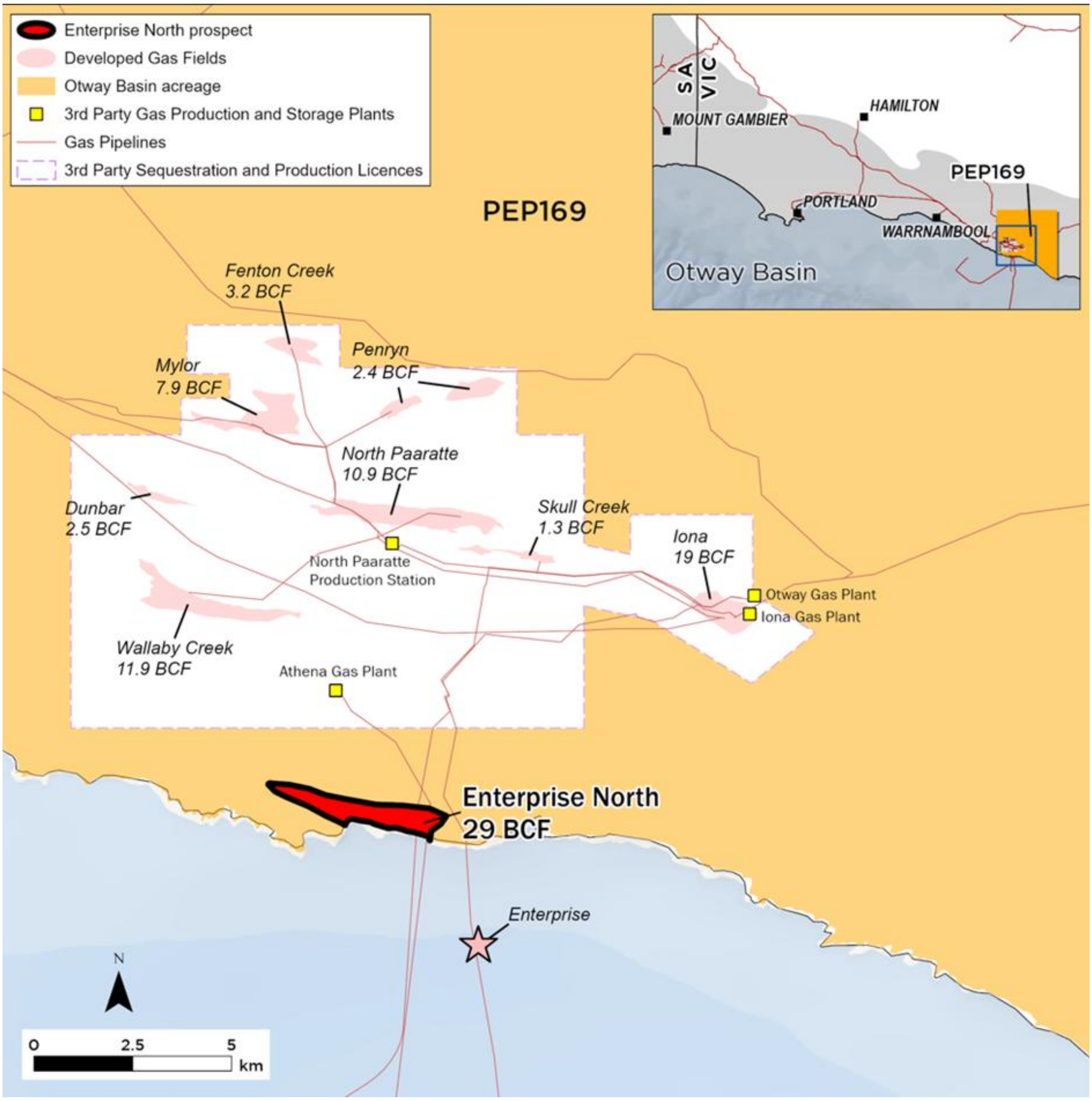
Note 1 – *Cautionary statement*: the estimated quantities of petroleum that may potentially be recovered by the application of a future development Project(s) relate to undiscovered accumulations. These estimates have both a risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons.

The resources above were first reported to ASX on 27 January 2026. Central 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 estimate continue to apply and have not materially changed.

The volumes of prospective resources included above represent unrisked recoverable volumes. No petroleum reserves or contingent resources have been attributed to Enterprise North at this time.

Modelling of a P50 success at Enterprise North indicates that possible gas production could result in a near doubling of Central's current gas production rates over the medium term. It is anticipated that over half of the gas at Enterprise North could be produced over a relatively short 3-year period given the formation's expected high permeability and the high flow rates achieved from neighbouring fields.

If successful, the Enterprise North project, or any of the several other significant gas targets already identified in the permit, would be highly value accretive to Central, with strong ex-field gas pricing expected and the relatively low infrastructure CAPEX required. Gas supplied from Enterprise North is likely to command strong ex-field gas prices and margins due to high gas prices in the Victorian market and relatively low transportation costs given the permit's proximity to market.



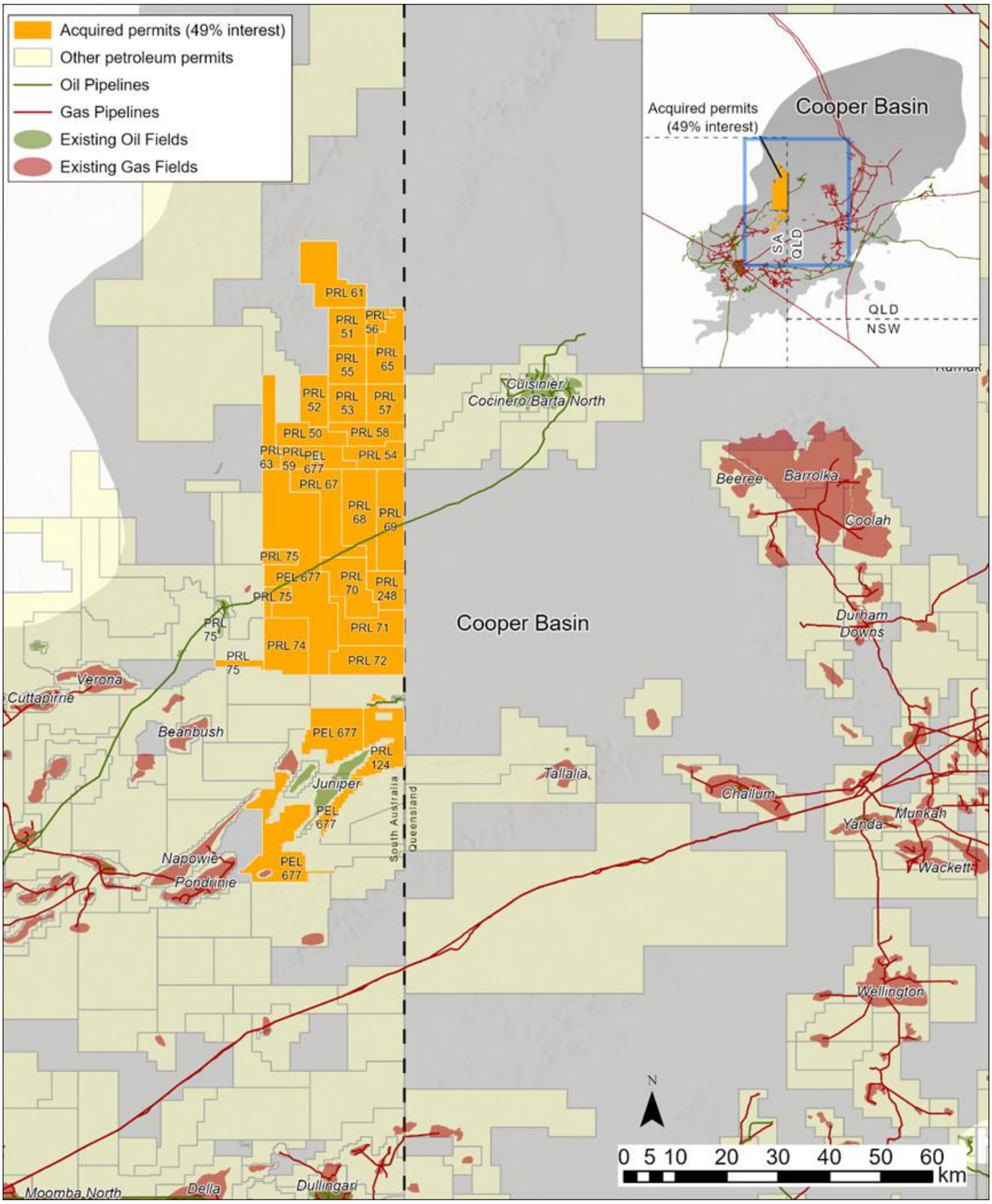
Cooper Basin – PRLs 50 - 59, 61, 63, 65 - 72, 74, 75, 124, 248 and PEL 677 (Central: 49% interest)

The Cooper Basin is a mature and well-established petroleum province with numerous historic and recent discoveries. Central has acquired a 49% interest in 24 Retention Leases (PRLs) and exploration permit PEL677 - areas that cover a large portion of the basin and are relatively underexplored, with the PRLs only recently coming out of suspension in 2025. The acreage is adjacent to multiple conventional oil and gas fields and discoveries.

Much of the acreage already has good seismic coverage via a combination of prior 2D and 3D surveys.

To date, 17 prospects and leads have been identified, with at least seven prospects considered drill-ready (potentially only requiring seismic reprocessing to mature). The initial focus will be on the higher value oil and gas targets, with plans to select two to three priority exploration targets to drill by early 2027.

Discoveries in the Cooper Basin can be brought online quickly via a network of existing oil and gas pipelines accessing the east coast gas market, existing oil export facilities and trucking corridors where oil pipelines are absent.



RESTRUCTURED AMADEUS BASIN SUB-SALT EXPLORATION

Central entered into a conditional agreement to vend two sub-salt exploration permits in the Northern Territory to UK-listed Georgina Energy Plc (Georgina) (LSE: GEX) in exchange for a 25% equity interest in the listed company.

The transaction would see Central sell its interests in exploration permits, EP112 (45% interest) and EP125 (30% interest) to Georgina. As a key condition to the sale, Georgina will need to complete an equity capital raising of at least £7 million (net of costs) and demonstrate that it has no less than £7 million in cash available immediately prior to completion. Georgina must drill the Mt Kitty / Jacko Bore prospect as soon as reasonably practicable, and in any event by no later than 6 June 2027.

On completion, Central will receive ordinary shares in Georgina such that it holds shares and rights equating to 25% of Georgina's fully-diluted share capital as at completion (e.g. post any equity raise or issue of dilutive securities prior to completion).

Central would be entitled to appoint a director to the Georgina board while it holds at least 15% of Georgina's issued capital.

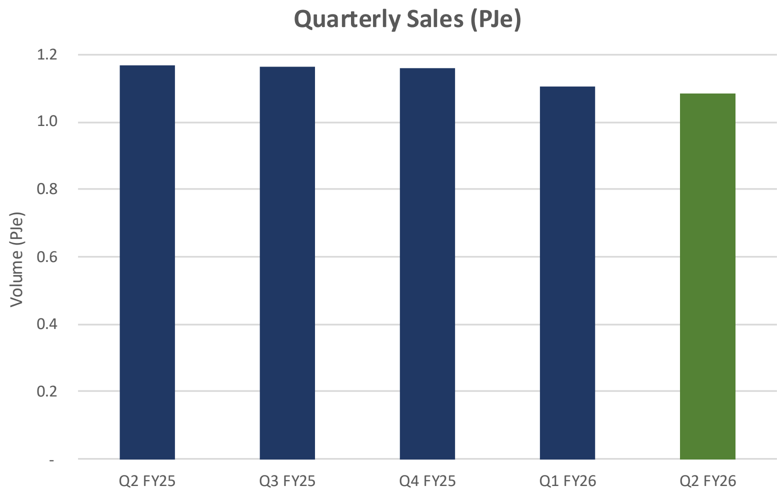
If the transaction completes, it will facilitate the restart of near-term sub-salt drilling in the Amadeus Basin and provide Central's shareholders with exposure to a focused helium exploration company with a broad range of major subsalt drilling targets in and around the Amadeus Basin. Central intends to ultimately distribute the Georgina shares to Central shareholders (subject to regulatory requirements).

Production Activities

SALES VOLUMES

Central supplied 1.09 PJe (Central share) of gas and oil from its fields in the Northern Territory (NT) in the December quarter, 2% lower than the September quarter due to oil offtake constraints at Mereenie.

Gas volumes in January 2026 are tracking 7% higher than the December quarter average, largely due to recent mitigations for the resolution of oil offtake constraints.



SALES REVENUE

Sales Revenue (unaudited)		Qtr v Qtr		YTD	
Product	**Unit**	**Q1 FY26**	**Q2 FY26**	**FY25**	**FY26**
Gas	$'000	10,435	**10,200**	16,578	**20,635**
Average unit price	*$/GJ*	*9.84*	***9.59***	*7.48*	***9.71***
Crude and Condensate	$'000	808	**235**	1,755	**1,043**
Total Sales Revenue	**$'000**	11,243	**10,435**	18,333	**21,678**

Sales revenue of $21.7m for the six months to December was 18% higher than the corresponding period in 2024 due to new gas contracts which commenced in January 2025.

Sales revenue for the December quarter was $10.4m, 7% lower than the previous quarter. Revenue was impacted by revised oil offtake arrangements at lower oil sales prices in order to maintain gas production volumes at as high a level as possible. Oil revenues are expected to remain at these lower levels until more attractive oil offtake arrangements can be secured.

MEREENIE OIL AND GAS FIELD (OL4 AND OL5) – NORTHERN TERRITORY

CTP - 25% interest (and Operator), Echelon Mereenie Pty Ltd - 42.5%, Horizon Australia Energy Pty Ltd - 25%, Cue Mereenie Pty Ltd - 7.5%

Average gross gas sales from the Mereenie field were 25.2 TJ/d (100% JV) for the December quarter, 3% lower than the previous quarter due to temporary well turndowns associated with oil offtake constraints, which were resolved by mid-December.

The gas sales capacity of the Mereenie field was approximately 28 TJ/d (100% JV) at the end of the quarter.

Oil sales averaged 178 bbls/d (100% JV) during the quarter, 39% lower than the previous quarter. Oil sales have been partially constrained by revised oil specifications to its existing offtake arrangements. Central has been managing this partial constraint through sales to alternative customers, increased flaring and temporarily shutting-in lower gas-to-oil ratio wells as required. From mid-December, alternative offtake arrangements for a portion of our oil production have alleviated the need to temporarily restrict production, allowing gas to be produced at full field capacity. Central is actively engaged in securing improved alternative commercial arrangements for the sale of Mereenie's produced oil. In the interim, oil sales and revenues are expected to remain lower than historic averages.

Early works have commenced for the drilling of two new development wells at Mereenie. The wells are planned to be drilled in late 2026 and can be quickly connected to existing production infrastructure. Joint Venture FID for the new wells is expected in parallel with the execution of the new long-term gas sale agreements, which is anticipated to occur in late February.

PALM VALLEY (OL3) – NORTHERN TERRITORY

CTP - 50% interest (and Operator), Echelon Palm Valley Pty Ltd - 35%, Cue Palm Valley Pty Ltd - 15%

Production from the Palm Valley field averaged 6.1 TJ/d over the quarter (Central share: 3.1 TJ/d), consistent with the previous quarter.

Sales capacity was approximately 6.5 TJ/d (100% JV) at the end of the quarter.

Two new wells are planned to significantly boost production at Palm Valley, with drilling planned to commence mid-year. Early works have commenced and the new wells can be quickly connected to existing production infrastructure. Joint Venture FID for the new wells is expected in parallel with the execution of new long-term gas sale agreements, which is anticipated to occur in late February.

DINGO GAS FIELD (L7) – NORTHERN TERRITORY

CTP - 50% interest (and Operator), Echelon Dingo Pty Ltd - 35%, Cue Dingo Pty Ltd - 15%

The Dingo gas field supplies gas directly to the Owen Springs Power Station in Alice Springs. Higher seasonal demand was reflected in sales volumes, which were close to contract maximums - up 4% quarter-on-quarter to 4.4 TJ/d (Central share: 2.2 TJ/d).

Exploration Activities

AMADEUS SUB-SALT EXPLORATION

Dukas (EP112), Jacko Bore (Mt Kitty) (EP125) and Mahler (EP82), operated by Santos.

CTP – 60% interest (EP82); 45% interest (EP112); 30% interest (EP125)

The Northern Territory Minister for Mining and Energy has advised he is prepared to grant a five year renewal of exploration permits EP82, EP112 and EP125, with the joint venturers having until early February to accept the renewal.

Central has elected to relinquish its interest in EP82 after considering holding and future drilling costs and the relatively small prospective resources. .

Central has entered into a conditional agreement to sell its interests in EP112 and EP125 to UK-listed Georgina Energy Plc (Georgina) (LSE: GEX) in exchange for a 25% equity interest in the company. If the transaction completes, drilling of a sub-salt exploration well in EP125 is expected in mid-2027, targeting helium and hydrocarbons. As a key condition to the sale, Georgina will need to complete an equity capital raising of at least £7 million (net of costs) and demonstrate that it has no less than £7 million in cash available immediately prior to completion. Georgina must drill the Mt Kitty / Jacko Bore prospect as soon as reasonably practicable, and in any event by no later than 6 June 2027.

Health, Safety and Environment

Central recorded no reportable safety incidents in the December quarter and the Company's TRIFR (Total Recordable Injury Frequency Rate) at the end of the quarter was nil.

A minor grass fire adjacent to the flare pit at Mereenie was reported in November with no injuries or material damage to the environment.

Corporate

CASH POSITION

Cash balances were $29.4m at the end of the quarter, higher than the $26.7 at the end of September, as a result of positive net operating cash inflows for the quarter of $4.1 million after exploration costs and net interest costs. Key components of operating cash flow included:

- Cash receipts from customers of $11.9m, including $0.4m take-or-pay receipts, were 8% lower than the prior quarter, consistent with the lower revenues;
- Cash production, transportation and corporate costs of $7.4 million including the payment of annual insurance premiums;
- Exploration related expenditures of $0.5m, including $0.3m of costs associated with Amadeus Basin sub-salt permits which will be reimbursed if the conditional sale agreements proceed to completion; and
- Net interest receipts of $0.17m. The scheduled $0.7m quarterly loan interest payment was capitalised into the loan balance.

There was $1.0m of capital expenditure during the quarter and $0.3m was incurred on the acquisition of interests in exploration permits in the Otway and Cooper Basins.

Net cash at 31 December was $5.3m.

Fees, salaries and superannuation contributions paid to directors, including the CEO and Managing Director, during the quarter amount to $0.25 million as disclosed at item 6.1 of the Appendix 5B.

The statement of cash flows for the quarter and financial year to date are attached to this report as Appendix 5B.

SHARE BUY-BACK

The on-market share buy-back program was adjusted to commence on 17 November 2025 and Central acquired 799,500 shares during the quarter for an outlay of $0.05m. A further 1,385,630 shares were purchased in January 2026, with a total of 2,185,130 shares purchased to date under the share buy-back (0.3% of the total starting issued capital). Central can buy-back up to 10% of its issued capital over a 12 month period. The ability to purchase shares on market is subject to factors such as prevailing share price, liquidity and other trading and regulatory constraints.

ISSUED CAPITAL

At the end of the quarter there were 751,964,455 ordinary shares on issue after the exercise of 14,333 rights in accordance with Central's Employee Rights Plan and the cancellation of 799,500 shares acquired pursuant to the on-market share buy-back program.

Leon Devaney
Managing Director and Chief Executive Officer
30 January 2026

This ASX announcement was approved and authorised for release by Leon Devaney, Managing Director and Chief Executive Officer

Annexure 1: Interests in Petroleum Permits and Licences

as at 31 December 2025

PETROLEUM PERMITS AND LICENCES GRANTED

Tenement	Location	Operator	CTP Consolidated Entity Registered Legal Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks)[1]	Amadeus Basin NT	Santos	60	0	Santos QNT Pty Ltd ("Santos")	100
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 112	Amadeus Basin NT	Santos	45	45	Santos	55
EP 115	Amadeus Basin NT	Central	100	100		
EP 125	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	50	50	Echelon Palm Valley Pty Ltd Cue Palm Valley Pty Ltd	35 15
OL 4 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Pty Ltd ("Echelon Mereenie") Horizon Australia Energy Pty Ltd ("Horizon") Cue Mereenie Pty Ltd ("Cue Mereenie")	42.5 25 7.5
OL 5 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Horizon Cue Mereenie	42.5 25 7.5
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	50	50	Echelon Dingo Pty Ltd ("Echelon Dingo") Cue Dingo Pty Ltd ("Cue Dingo")	35 15
RL 3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna)	Amadeus Basin NT	Central	100	100		

PETROLEUM PERMITS AND LICENCES UNDER APPLICATION

Tenement	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111	Amadeus Basin NT	Santos	50	50	Santos	50
EPA 124 [2]	Amadeus Basin NT	Santos	50	50	Santos	50
EPA 129	Wiso Basin NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133	Amadeus Basin NT	Central	100	100		
EPA 137	Amadeus Basin NT	Central	100	100		
EPA 147	Amadeus Basin NT	Central	100	100		
EPA 149	Amadeus Basin NT	Central	100	100		
EPA 152	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		
EPA 296	Wiso Basin NT	Central	100	100		

PIPELINE LICENCES

Pipeline Licence	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	25	25	Echelon Mereenie Horizon Cue Mereenie	42.5 25 7.5
PL 30	Amadeus Basin NT	Central	50	50	Echelon Dingo Cue Dingo	35 15

Notes:

[1] As announced on 19 December 2025, Central provided notice of its withdrawal from the EP82 Joint Venture with Santos.

[2] In March 2018 Central received notice from DME that EPA124 had been placed in moratorium on 6 December 2017 for a five year period which ended on 6 December 2022.

Abbreviations

1P	Proved reserves
2P	Proved and Probable reserves
GJe	Gigajoules equivalent*
NGP	Northern Gas Pipeline
NT	Northern Territory
PJ	Petajoules
PJe	Petajoules equivalent*
TJ/d	Terajoules per day

*equivalent includes oil converted at 5.816 PJ per million barrels of oil

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 Central Petroleum Limited (**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 programs 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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Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity
CENTRAL PETROLEUM LIMITED

ABN	Quarter ended ("current quarter")
72 083 254 308	31 DECEMBER 2025

	Consolidated statement of cash flows	Current quarter $A'000	Year to date $A'000 *(6 Months)*
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	11,892	24,868
1.2	Payments for		
	(a) exploration & evaluation	(540)	(1,288)
	(b) development	–	–
	(c) production and gas purchases	(6,523)	(15,924)
	(d) staff costs net of recoveries	(342)	(1,927)
	(e) administration and corporate costs (net of recoveries)	(539)	(707)
1.3	Dividends received (see note 3)	–	–
1.4	Interest received	242	481
1.5	Interest and other costs of finance paid	(70)	(829)
1.6	Income taxes paid	–	–
1.7	Government grants and tax incentives	5	5
1.8	Other (provide details if material)	–	–
1.9	**Net cash from / (used in) operating activities**	**4,125**	**4,679**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire or for:		
	(a) entities	–	–
	(b) tenements	(309)	(309)
	(c) property, plant and equipment	(1,017)	(1,983)
	(d) exploration & evaluation	–	–
	(e) investments	–	–
	(f) other non-current assets	–	–

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date $A'000** ***(6 Months)***
2.2	Proceeds from the disposal of:		
	(a) entities (net of transaction costs)	–	–
	(b) tenements	–	–
	(c) property, plant and equipment	–	–
	(d) investments	–	–
	(e) other non-current assets	–	–
2.3	Cash flows from loans to other entities	–	–
2.4	Dividends received (see note 3)	–	–
2.5	Other - Net (lodgement) or redemption of security deposits	–	(248)
2.6	**Net cash from / (used in) investing activities**	**(1,326)**	**(2,540)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	–	–
3.2	Proceeds from issue of convertible debt securities	–	–
3.3	Proceeds from exercise of options	–	–
3.4	Transaction costs related to issues of equity securities or convertible debt securities	(4)	(4)
3.5	Proceeds from borrowings	–	–
3.6	Repayment of borrowings	–	–
3.7	Transaction costs related to loans and borrowings	–	–
3.8	Dividends paid	–	–
3.9	Other		
	- principal elements of lease payments	(121)	(201)
	- on market share buy-back	(50)	(50)
3.10	**Net cash from / (used in) financing activities**	**(175)**	**(255)**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	26,731	27,471
4.2	Net cash from / (used in) operating activities (item 1.9 above)	4,125	4,679
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(1,326)	(2,540)

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date $A'000** ***(6 Months)***
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(175)	(255)
4.5	Effect of movement in exchange rates on cash held	–	–
4.6	**Cash and cash equivalents at end of period**	**29,355**	**29,355**

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]	29,355	26,731
5.2	Call deposits	–	–
5.3	Bank overdrafts	–	–
5.4	Other (provide details)	–	–
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**29,355**	**26,731**

[1] *Includes the Group's share of Joint Venture bank accounts (Current Quarter $202,844, Previous Quarter $2,725,944)*

6.	**Payments to related parties of the entity and their associates**	**Current quarter $A'000**
6.1	Aggregate amount of payments to related parties and their associates included in item 1	248
6.2	Aggregate amount of payments to related parties and their associates included in item 2	–
Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.		

Includes Directors Fees, Salaries, and superannuation contributions.

7.	**Financing facilities** *Note: the term "facility' includes all forms of financing arrangements available to the entity.* *Add notes as necessary for an understanding of the sources of finance available to the entity.*	**Total facility amount at quarter end $A'000**	**Amount drawn at quarter end $A'000**
7.1	Loan facilities	28,000	24,070
7.2	Credit standby arrangements	–	–
7.3	Other (please specify)	–	–
7.4	**Total financing facilities**	28,000	24,070
7.5	**Unused financing facilities available at quarter end**		3,930
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well.		
	7.1 – Represents the Macquarie Bank loan facility which is a secured term loan facility maturing 31 December 2029 with interest accruing quarterly. Principal repayments commence March 2027 and continue quarterly thereafter until maturity The interest rate at the end of the current quarter is 11.7875% (floating interest rate).		

8.	**Estimated cash available for future operating activities**	**$A'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	4,125
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	–
8.3	Total relevant outgoings (item 8.1 + item 8.2)	4,125
8.4	Cash and cash equivalents at quarter end (item 4.6)	29,355
8.5	Unused finance facilities available at quarter end (item 7.5)	3,930
8.6	Total available funding (item 8.4 + item 8.5)	33,285
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**N/A**

Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.

8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:

8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?

Answer: N/A

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: N/A

8.8.3	Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?
	Answer: N/A
	Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

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.

Date: 30 January 2026...

Authorised by: Leon Devaney, Managing Director and CEO.............
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.
2. If this quarterly cash flow 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 cash flow 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.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [*name of board committee – eg Audit and Risk Committee*]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.