CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

ASX:CTP

"We start 2023 on a positive note, with increased production from our PV12 well being sold into a strong gas market and with commencement of a major sub-salt exploration program to look forward to this year."

Leon Devaney
MD and CEO

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Central Petroleum

Activities Report and ASX Appendix 5B

REVIEW OF OPERATIONS FOR THE QUARTER ENDED 31 DECEMBER 2022

Highlights

- **Palm Valley drilling success:** The Palm Valley 12 P1 lateral well was successfully completed, tied-in to the Palm Valley processing facilities and flowing gas to market at greater than 10 TJ/day from late November.
- **New gas sales agreement:** A new gas sales agreement for the sale of 0.55 PJ of gas to South32 over two years from 1 January 2023 was executed.
- **Cash balance** at the end of the quarter was $13.7 million, compared to the $15.6 million balance at 30 September 2022:
  - Lower net operating inflows of $0.2 million (before exploration and finance costs) as the temporary closure of the Northern Gas Pipeline (NGP) restricted sales volumes and annual insurance and staff incentives payments were made.
  - $0.8 million of capital expenditure, being mainly sustaining CAPEX.
  - Net finance payments of $1.0 million after $1.0 million was drawn down under the expanded finance facility.
- **Sales volume** was down 8% on the previous quarter at 1.07 PJe (Petajoule equivalent) as the temporary NGP outage extended until mid-December, preventing spot gas sales to east coast customers for most of the quarter.
  - Sales volumes are expected to rebound in the March quarter as the NGP is now fully operational and Palm Valley gas production has been boosted following commissioning of the new PV12 well in late November.
- **Unit sales prices** across the portfolio decreased from the extraordinary spot market-driven peaks of the previous two quarters to an average of $6.78/GJe (Gigajoule equivalent), as Central was unable to access east coast customers and spot markets due to the NGP outage.
- **Sales revenue** of $7.2 million for the quarter was down 23.2% from the September quarter reflecting the lower volumes and softer realised prices.
- **Debt facility increased** by two separate tranches of $6 million to fund increased production across Central's Amadeus Basin gas projects. An initial $1 million was drawn down to activate the first tranche in December with the second tranche remaining subject to satisfaction of certain conditions precedent.
- **Net Debt** was $16.8 million at 31 December, up from $15.1 million at the end of September reflecting the lower cash balance.
- **Strategic Review:** The Board initiated a strategic review of Central's asset portfolio, growth strategies and capital structure. RBC Capital Markets was appointed as advisor and is working with Central to assess various options to realise value for shareholders.

Message from Managing Director and CEO

The final quarter of 2022 brought a mix of new challenges and opportunities for Central Petroleum, and I think on balance, it's fair to say we've ended the quarter in a better position than where we started.

In early October we conducted the first flow test from the final appraisal lateral of our PV12 well at Palm Valley which had been unsuccessful in reaching its deep exploration target and we have been very happy with the results so far. The well has flowed gas in excess of 11 TJ per day, well above our pre-drilling expectations. The well was successfully tied-in to our Palm Valley facilities and has been flowing gas to customers from late November.

This well has boosted gas production at Palm Valley from 5.5 TJ/d towards the facility maximum of 15 TJ/d in January (Central's 50% interest: 7.5 TJ/d). This extra production will provide welcome cash flow for Central in coming months and also provide new gas supply for Australian customers. The performance of this well should allow Central to book new gas reserves around mid-year and supports the drilling of more wells at Palm Valley to target additional gas reserves. After the many challenges encountered during the exploration drilling part of the program, this is a very welcome outcome.

We started the quarter with the Northern Gas Pipeline (NGP), our gas transportation route to eastern markets, closed by the operator for safety reasons related to low flow rates, limiting our non-firm gas sales to customers in the Northern Territory. Fortunately, we were able to redirect most of our non-firm gas to users in the NT to minimise the impact of this pipeline outage on Central's sales volume over the quarter.

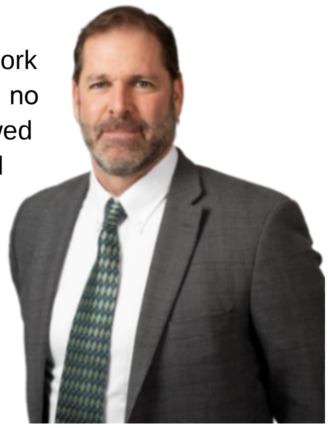
Notwithstanding these sales, the disruption to the NGP did mean our overall gas sale volumes and revenues for the quarter were down on previous quarters which had benefitted from record market prices. With the NGP reopened from mid-December and the Palm Valley production volumes now double that of November, we expect revenues to rebound in the March quarter.

The Board and management continues to work with RBC Capital Markets to assess various opportunities to crystalise value for shareholders. I'm sure our shareholders will appreciate that a measured approach to these activities is necessary and it would be counter-productive for us to speculate on timeframes or outcomes at this time.

At the same time, however, in parallel with the strategic review, we continue to work to create value through our portfolio of assets. Plans are progressing to increase capacity at Mereenie within the next twelve months through recompletion of existing wells and new development wells, subject to final joint venture approval. To fund this activity, we successfully agreed an expansion to our debt facility by up to $12 million in December in two equal tranches of $6 million, with the second tranche remaining subject to conditions precedent before being able to be drawn down.

Preparations continue for the three Amadeus Basin sub-salt exploration wells planned to start later this year. With the Peak Helium farmout providing critical funding for this program, final commitment to these wells is linked to outstanding regulatory approvals which are expected in the first quarter of 2023.

We continue to prioritise our resources on activities which are more likely to realise value for shareholders and will surrender some of our large exploration portfolio – specifically, our interests in the Southern Georgina Basin in western Queensland and the Ooraminna Retention Leases in the Amadeus Basin. The previous results in these permits, coupled with the changing regulatory regime and high financial commitments have led us to conclude that our efforts and resources should be focussed on our other opportunities. Similarly, we have allowed our arrangements to support the proposed Amadeus to Moomba gas pipeline to lapse and will revisit these once we better assess changes to the regulatory regimes and results become available from the subsalt exploration program.



The volatile energy markets of mid-2022 led the Federal Government to introduce a framework for capping gas prices going forward. Given that Central's gas is largely contracted for 2023, no material impact on revenue is expected at this stage, noting that the Price Order will be reviewed in mid-2023 and the $12/GJ price cap is greater than Central's current average realised portfolio price ($6.78/GJ in the December quarter). Central is seeking further clarification of the new regulations to support contracting gas for 2024 and beyond.

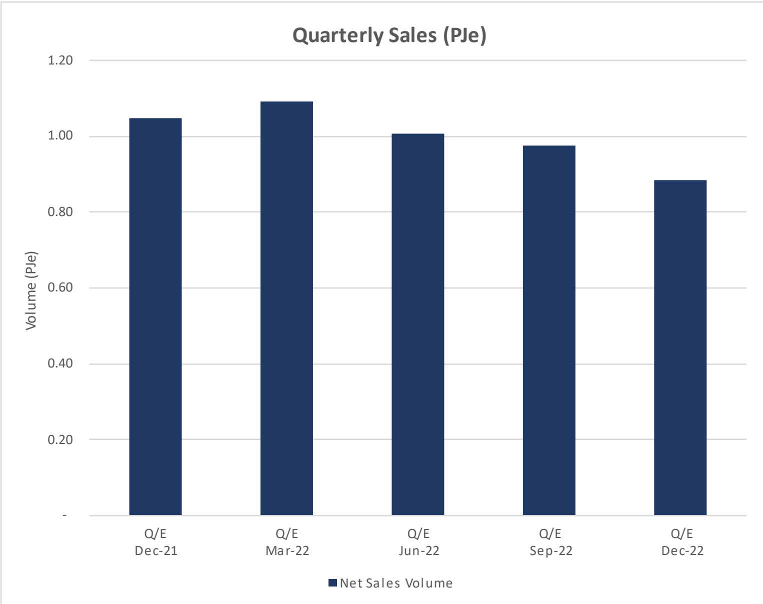
So we start 2023 on a positive note, with the increased production from our PV12 well being sold into a strong gas market and with commencement of a major sub-salt exploration program to look forward to this year. We look forward to sharing our progress with shareholders as the year advances.

Leon Devaney

Leon Devaney, Managing Director and Chief Executive Officer

Production Activities

SALES VOLUMES



The Northern Gas Pipeline (NGP) temporary outage which extended from early September to mid-December limited gas sales to customers in the Northern Territory for most of the quarter.

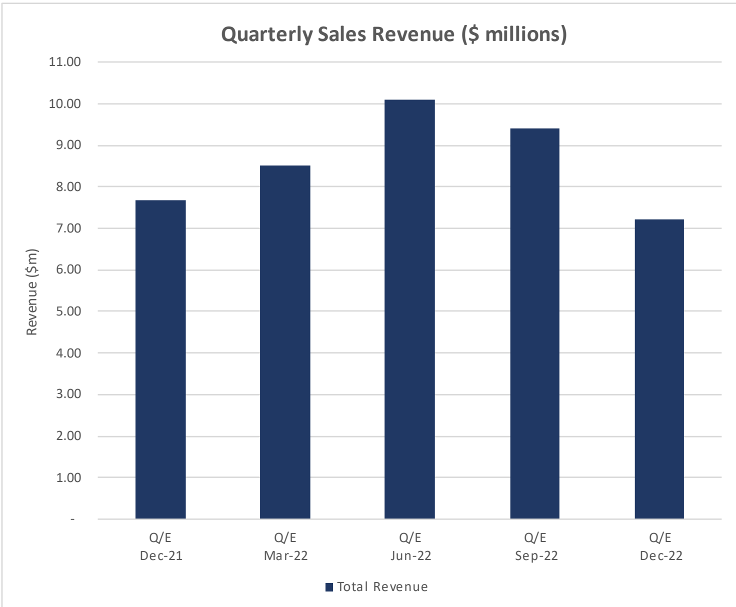
As a result, volumes were down 8% at 1.07 PJe).

With the NGP re-opening in mid-December, sales volumes are expected to rebound in the March quarter, boosted by production from the newly-commissioned Palm Valley 12 well which is currently producing at over 9.5 TJ/day (Central share: 4.75 TJ/day).

SALES REVENUE

Revenues in the December quarter were impacted by the temporarily constrained pipeline transportation to east coast markets, with both volume and realised prices lower in the December quarter as a result.

In the preceding June and September quarters, Central had benefitted from the extraordinarily high spot gas prices driven by the need for gas to supplement reduced coal-fired electricity generation. These prices have since returned to levels more consistent with previous periods, with realised portfolio prices of $6.78/GJe being 8.2% higher than in December 2021, but 16.5% lower than September 2022.



Revenues in the December quarter were $7.2 million, down 5.8% on the corresponding December quarter in 2021, due to the lower volumes, and 23.2% below the September 2022 quarter due to both lower volumes and prices.

Central's $16.7 million half year revenue is lower than the same period in FY2022 due to the lower ownership interests from 1 October 2021, but after adjusting for that impact, revenues were 6.7% higher than 1H FY2022 on a like-for-like basis. This was achieved on lower like-for-like volumes (down 11.4% on 1H FY2022). The realised oil price was 10% higher in 1H FY2023 and the average gas portfolio price was up 22% on 1H FY2022.

Sales revenues are expected to rebound sharply in the March 2023 quarter, with the NGP now providing access to east coast markets and higher volume being supplied from the newly commissioned PV12 well.

Sales Revenue*		FY23		YTD	
Product	Unit	Q1	Q2	2022	2023
Gas	$'000	8,441	**6,280**	20,475	**14,721**
Crude and Condensate	$'000	978	**953**	3,055	**1,931**
Total Sales Revenue	**$'000**	9,419	**7,233**	23,530	**16,652**
Revenue per unit	$/GJe	$8.12	**$6.78**	$6.18	**$7.48**

*Unaudited. Central's revenues from Q2 FY22 reflect a reduced share of production following completion of the sale of 50% of its interests in the Mereenie, Palm Valley and Dingo fields to NZOG and Cue.

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

CTP - 25% interest (and Operator), Macquarie Mereenie Pty Ltd - 50%, NZOG Mereenie Pty Ltd - 17.5%, Cue Mereenie Pty Ltd - 7.5%

Gross gas sales from the field were impacted by the outage on the NGP for most of the quarter and natural field decline, averaging 23.3 TJ/d (100% JV), compared to 28.8 TJ/d in the September quarter.

The sales capacity of the Mereenie field was approximately 31 TJ/d (100% JV) at the end of the quarter and production volume has returned to 30 TJ/d in January 2023 with the reopening of the NGP.

Oil sales averaged 359 bbls/d (100% JV) during the quarter.

Central is planning to increase production from Mereenie in the first half of 2023, with the joint venturers to consider a development program comprising recompletion of up to six existing wells and drilling of two new development wells.

PALM VALLEY (OL3) – NORTHERN TERRITORY

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

The Palm Valley field's production was boosted in December with the commissioning of the new PV12 gas production well which is currently producing at around 9.5 TJ/d (Central share 4.75 TJ/d). The new well boosted average field production from 5.5 TJ/d in November to 11.3 TJ/d in December (100% JV).

The new well, which only came online in late November resulted in the Palm Valley field producing at an average of 7.4 TJ/d over the quarter (Central share: 3.7 TJ/d), significantly higher than the 5.7 TJ/d average in the September quarter.

Sales capacity was approximately 14 TJ/d (100% JV) at the end of the quarter following an overhaul of compression facilities and production from Palm Valley in the March 2023 quarter is expected to average almost double that of the December quarter.

DINGO GAS FIELD (L7) – NORTHERN TERRITORY

CTP - 50% interest (and Operator), NZOG 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. Nominated volumes supplied over the quarter were seasonally lower than the preceding quarter and averaged 3.1 TJ/d (Central share: 1.55 TJ/d), 9% higher than the corresponding December 2021 quarter. The daily contract volume of 4.4 TJ/d (Central share: 2.2 TJ/d) is subject to take-or-pay provisions under which Central is paid its share annually in January for the previous calendar year's shortfall.

Health, Safety and Environment

Central recorded no MTI / LTIs in the December quarter and the Company's TRIFR (Total Recordable Injury Frequency Rate) at the end of the quarter was 8.2. One environmental incident was reported to regulators after vegetation in a small area adjacent to the Palm Valley 12 drill site was impacted by an overspray of formation water, unexpectedly encountered during drilling, from the flare pit.

Appraisal Activities

RANGE GAS PROJECT (ATP 2031) – QUEENSLAND

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

Production testing of three pilot wells continued throughout the quarter, with gas production rates increasing late in the quarter to an aggregate 55 GJ/d. The increase is largely due to the new wells (R9, R10), which saw step changes in production in December as they continue to be de-watered.

The production testing is intended to provide key information regarding reservoir productivity (initially via water rates), gas desorption (when gas is first produced), zonal contribution (how much each coal seam is contributing) and the initial production profiles of gas and water ramp-up.

Further activity to progress the Range project will be subject to ongoing JV discussions and Central's strategic review.

Exploration Activities

PALM VALLEY 12 EXPLORATION WELL

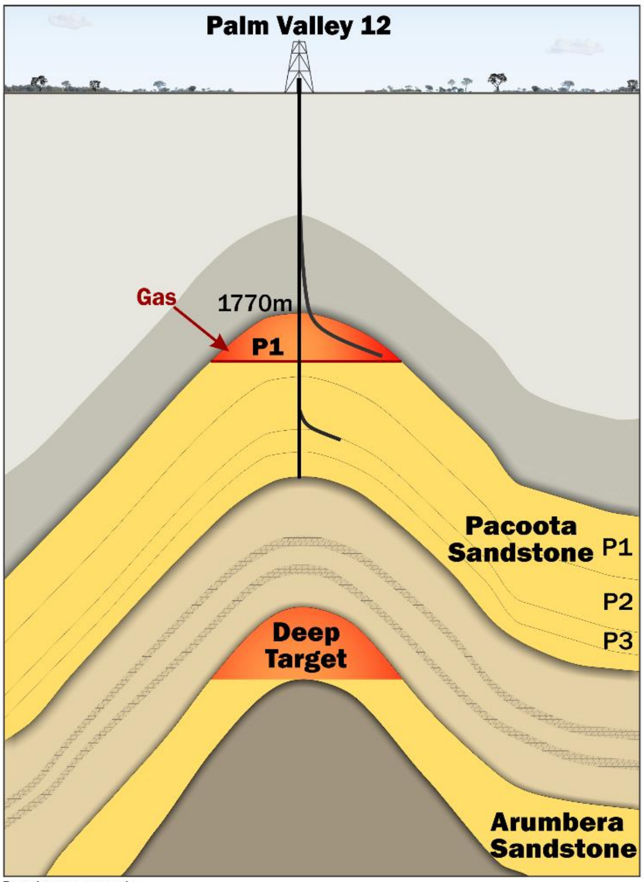
CTP - 50% interest, NZOG Palm Valley Pty Ltd - 35%, Cue Palm Valley Pty Ltd - 15%

The Palm Valley 12 well was successfully completed as a production well in late November and has been producing gas rates greater than of 9.5 TJ/d.

After targeting two deeper exploration targets in previous quarters, a second lateral well (PV12 ST2) was side-tracked to test the shallower Pacoota (P1) Sandstone (approx. 1,770m depth), which is the current producing zone for the Palm Valley gas field.

The PV12 ST2 lateral appraisal well was drilled to a measured depth of 3,039m in the P1 Sandstones in early October and flowed gas at 11.8 million standard cubic feet per day when tested in mid-October.

The well was connected into the Palm Valley production infrastructure, and first gas was supplied to market in late November.



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AMADEUS SUB-SALT EXPLORATION

Southern Amadeus Basin

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

CTP – 35% interest (EP112); 24% interest (EP125); 29% interest (EP82), each post-farmout to Peak Helium (Amadeus Basin) Pty Ltd (see Annexure 1)

Three sub-salt exploration wells are planned to be drilled in the Southern Amadeus Basin, commencing 2023, targeting hydrocarbons, helium and naturally occurring hydrogen.

Santos, as operator, continued key activities for the three well program during the quarter, including rig contracting, ordering long lead items and environmental and land access approvals.

Upon completion of the farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd (Peak), Central is to be free carried (i.e. funded) by Peak for two of the new sub-salt exploration wells (capped at $20 million gross cost per well), one at the Mahler prospect (EP 82) and the other at the Mt Kitty prospect (EP 125).

Completion of Central's farmouts to Peak is subject to the usual conditions precedent for a transaction of this nature including Joint Venture, Central Land Council, royalty holder and NT regulatory approvals. Progress towards completion continued during the quarter, with Peak currently awaiting final regulatory approvals from the NT Government. The satisfaction date was extended during the quarter to 31 January 2023 (from 30 November 2022).

RELINQUISHMENTS

As part of an ongoing strategic review, Central has considered its portfolio of permits and applications with a view to prioritising those areas which are more likely to deliver value for shareholders. After analysing past exploration results and taking into consideration the potential future costs and risks of exploration, appraisal and development, increasing regulatory hurdles and costs and recent government intervention in gas markets, Central intends to surrender its interests in the Georgina Basin (Qld titles ATP 909, ATP 911 and ATP 912) and the Ooraminna Retention Licences (NT titles RL 3 and RL 4).

Central would have been required to invest significant capital on exploration and appraisal activities in these areas in 2023 to satisfy the minimum permit commitments.

Central has not recognised any petroleum reserves or resources to date for these permits and expects to recognise an impairment charge of $0.4 million in its half year accounts.

Central will work with the relevant regulators in NT and Qld to complete all necessary rehabilitation activities.

In addition, Central has been advised that its application for exploration permit EPA120 in the NT will not be approved due to overlapping sites of conservation significance.

Commercial

GAS MARKET OUTLOOK

Late in 2022, the Federal Government implemented a price cap of $12/GJ on the sale of gas produced in 2023 under the Gas Market Emergency Price Order (Price Order) which created a level of uncertainty in the market around elements of the Price Order. The ACCC has since issued guidelines to address the uncertainty which provided examples covering various scenarios.

Given that Central's gas is largely contracted for 2023, no material impact on revenue is expected at this stage, noting that the Price Order will be reviewed in mid-2023 and the $12/GJ price cap is higher than Central's current average realised portfolio price ($6.78/GJ in the December quarter). Central is seeking further clarification of the new regulations to support contracting gas for 2024 and beyond.

NEW GAS SALES AGREEMENT

During the quarter, Central executed a new gas sales agreement (GSA) for the sale of 0.55 PJ of gas to South 32 over two years from 1 January 2023. This comprises Central's share of a total of 2.19 PJ of gas to be supplied to South 32 in CY2023/24 from the Mereenie gas field. The GSA is at a fixed price reflecting current strong market conditions and is for firm gas supply with take-or-pay provisions.

AMADEUS TO MOOMBA GAS PIPELINE (AMGP)

Central has allowed arrangements to support the proposed Amadeus to Moomba gas pipeline to lapse, pending future exploration results and resolution of market uncertainty in the wake of the Federal Government's recent intervention in gas markets. In August 2020, Central together with Macquarie Mereenie, entered into a non-binding memorandum of understanding (MOU) with AGIG to enable the development of the AMGP to provide a direct, more efficient route to eastern gas markets.

Central re-directed capital from its 2022 exploration program to boost production from its existing fields to meet gas demand in eastern Australia and has not yet accessed new gas resources necessary to underwrite the development of the AMGP as originally hoped. Central plans to participate in a three well sub-salt exploration program in the Amadeus Basin from mid-2023 which, if successful, could provide sufficient new gas volumes to support the AMGP project.

STRATEGIC REVIEW

A strategic review of Central's asset portfolio, growth strategies and capital structure is being conducted by the Central Board. RBC Capital Markets was appointed as advisor in late September and is working with Central to assess various options to realise value for shareholders.

Corporate

CASH POSITION

Cash balances were $13.7 million at the end of the quarter, down from $15.6 million held at the end of September.

The net cash outflow from operations for the quarter was $0.7 million after exploration costs and finance charges. Key components of operating cash flow included:

- Cash receipts from customers during the quarter of $6.3 million, impacted by lower sales volumes resulting from the temporary closure of the NGP from September to mid-December.
- Exploration expenditure of $0.2 million, including the Range CSG pilot operations and planning for the 2023 Amadeus sub-salt exploration program.
- Cash production and transportation costs of $4.3 million.
- Staff and administration costs of $2.2 million, including strategic review costs, annual insurance premiums and staff incentives, net of recoveries from joint ventures.
- Interest charges of $0.7 million.

Capital expenditure amounted to $0.8 million, being largely sustaining CAPEX.

Under the carry arrangements relating to the partial asset sale, the new joint venturers at Mereenie, Palm Valley and Dingo agreed to pay $40 million of Central's share of certain future exploration and development costs in those fields. In the December quarter $1.2 million of Central's exploration costs and $6.8 million of development costs were carried under these arrangements. At the end of December, $3.4 million remained available for future use.

Fees, salaries, annual incentives and superannuation contributions paid to Directors, including the Managing Director, during the quarter amount to $0.44 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.

EXPANDED DEBT FACILITY

In November, Central entered into an agreement with Macquarie Bank Limited (Macquarie) for the expansion of its existing debt facility (Facility) for up to $12 million to fund increased production across its Amadeus Basin gas projects.

The new Facility consists of two separate tranches of $6 million, each of which can be activated upon satisfaction of certain conditions precedent which include requirements that Macquarie be satisfied that:

- Central's capital commitments under agreed development plans and exploration projects are fully-funded from available facilities and expected operating cash flows for the term of the facility; and
- Certain new gas sale agreement thresholds are met.

Access to funds under a tranche will be cancelled unless the tranche has been at least partly utilised by:

- For the first tranche, 31 December 2022
- For the second tranche, 31 December 2023.

Any funds drawn under the expanded Facility will be repaid as follows:

- For the first tranche, 50% to repaid by quarterly equal instalments between the date of utilisation and 30 September 2025.
- For the second tranche, 40% to be repaid by quarterly equal instalments between the date of utilisation and 30 September 2025.

Central will pay a commitment fee on any undrawn Facility funds equal to 40% of the Facility interest rate. Other key terms, including interest rate margin and financial covenants will remain unchanged.

Central may elect not to utilise the unused portion of the expanded Facility and may repay any drawn funds at any time without penalty.

Central has granted Macquarie a royalty equal to 0.25% of the gross well head value derived from a 35% participating interest in exploration permit 112 (Northern Territory) as part of the consideration for the new Facility.

Central satisfied all conditions precedent for the first tranche in December and has drawn-down $1 million.

ISSUED CAPITAL

At the end of the quarter there were 729,260,450 ordinary shares on issue, including 3,353,001 new shares issued during the quarter upon exercise of previously-issued share rights.

Leon Devaney
Managing Director and Chief Executive Officer
31 January 2023

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 2022

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(a)]	Amadeus Basin NT	Santos	60	60	Santos QNT Pty Ltd ("Santos")	40
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 105	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 112 [1(b)&2]	Amadeus Basin NT	Santos	30	45	Santos	55
EP 115	Amadeus Basin NT	Central	100	100		
EP 125 [1(c)]	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	50	50	NZOG Palm Valley Pty Ltd Cue Palm Valley Pty Ltd	35 15
OL 4 (Mereenie)	Amadeus Basin NT	Central	25	25	Macquarie Mereenie Pty Ltd ("Macquarie Mereenie") NZOG Mereenie Pty Ltd ("NZOG Mereenie") Cue Mereenie Pty Ltd ("Cue Mereenie")	50 17.5 7.5
OL 5 (Mereenie)	Amadeus Basin NT	Central	25	25	Macquarie Mereenie NZOG Mereenie Cue Mereenie	50 17.5 7.5
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	50	50	NZOG Dingo Pty Ltd ("NZOG Dingo") Cue Dingo Pty Ltd ("Cue Dingo")	35 15
RL 3 (Ooraminna) [3]	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna) [3]	Amadeus Basin NT	Central	100	100		
ATP 909 [3]	Georgina Basin QLD	Central	100	100		
ATP 911 [3]	Georgina Basin QLD	Central	100	100		
ATP 912 [3]	Georgina Basin QLD	Central	100	100		
ATP 2031 (Range)	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 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 [4]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 120 [5]	Amadeus Basin NT	Central	0	0		
EPA 124 [6]	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 [7]	Pedirka Basin NT	Central	0	0		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133 [8]	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 [6]	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		

Tenement	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
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	Macquarie Mereenie	50
					NZOG Mereenie	17.5
					Cue Mereenie	7.5
PL 30	Amadeus Basin NT	Central	50	50	NZOG Dingo	35
					Cue Dingo	15

Notes:

[1] As announced on 9 February 2022, Central entered into a farmout of various interest in certain Amadeus Basin exploration tenements to Peak Helium (Amadeus Basin) Pty Ltd subject to the usual conditions precedent for a transaction of this nature being met by 31 January 2023. Upon completion, Peak Helium (Amadeus Basin) Pty Ltd will earn partial transfer of Central's interest in three permits as follows:

(a) 31% in EP82, excluding Dingo Satellite Area (Central's interest will change from 60% to 29%)

(b) 10% in EP112 (Central's interest will change from 45% to 35%); and

(c) 6% in EP125 (Central's interest will change from 30% to 24%)

[2] As announced on 2 August 2021, Santos did not elect that Central be carried for the first $3 million of Dukas-1 well costs and therefore its interest in EP112 (including Dukas-1 well) will decrease from 70% to 55% (Central's interest in EP112 will increase from 30% to 45%)

[3] Central intends to surrender its interests in the Georgina Basin (Qld permits ATP 909, ATP 911 and ATP 912) and the Ooraminna Retention Lease (NT permits RL 3 and RL 4).

[4] On 16 December 2021 Central received notice from the NT Department of Industry Tourism and Trade (DITT) that EPA111 had been placed in moratorium for a period of 5 years from 9 December 2021 until 9 December 2026.

[5] On 1 November 2022 Central received notice from DITT that EPA120 would not be granted as it overlays a Reserved Block which was declared on 1 September 2021. Central does not intend to appeal the decision.

[6] On 22 March 2018 (in respect of EPA124) and on 23 March 2018 (in respect of EPA152) Central received notice from DITT that EPA124 and EPA152, as applicable, had been placed in moratorium on 6 December 2017 for a five year period ending on 6 December 2022. In December 2022 Central submitted applications to DITT for consent to negotiate the grant of these exploration permits.

[7] This exploration permit application has been disposed. At the instruction of the acquirer, Central notified DITT to withdraw the application for EPA131, which withdrawal was subsequently accepted by DITT.

[8] This exploration permit application was placed into moratorium on 22 October 2015 for a five (5) year period ending on 22 October 2020. On 25 February 2021, Central was provided with consent to negotiate the grant of this exploration permit.

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.*

This document may contain forward-looking statements. Forward looking statements are only predictions and are subject to risks, uncertainties and assumptions which are outside the control of the Company. These risks, uncertainties and assumptions include (but are not limited to) commodity prices, currency fluctuations, economic and financial market conditions in various countries and regions, environmental risks and legislative, fiscal or regulatory developments, political risks, project delay or advancement, approvals and cost estimates. Actual values, results or events may be materially different to those expressed or implied in this document. Given these uncertainties, readers are cautioned not to place reliance on forward looking statements. Any forward looking statement in this document is valid only at the date of issue of this document. Subject to any continuing obligations under applicable law and the ASX Listing Rules, or any other Listing Rules or Financial Regulators' rules, the Company and its subsidiaries and each of their agents, directors, officers, employees, advisors and consultants do not undertake any obligation to update or revise any information or any of the forward looking statements in this document if events, conditions or circumstances change or that unexpected occurrences happen to affect such a statement. Sentences and phrases are forward looking statements when they include any tense from present to future or similar inflection words, such as (but not limited to) "forecast", "believe," "estimate," "anticipate," "plan," "predict," "may," "hope," "can," "will," "should," "expect," "intend," "is designed to," "with the intent," "potential," the negative of these words or such other variations thereon or comparable terminology, may indicate forward looking statements.

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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 2022

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		6,344	16,050
1.2	Payments for			
	(a)	exploration & evaluation (if expensed)	(221)	(6,077)
	(b)	development	–	–
	(c)	production and gas purchases	(4,283)	(10,786)
	(d)	staff costs net of recoveries	(785)	(1,161)
	(e)	administration and corporate costs (net of recoveries)	(1,411)	(1,662)
1.3	Dividends received (see note 3)		–	–
1.4	Interest received		142	230
1.5	Interest and other costs of finance paid		(698)	(1,297)
1.6	Income taxes paid		–	–
1.7	Government grants and tax incentives		–	–
1.8	Other (provide details if material)		238	238
1.9	**Net cash from / (used in) operating activities**		**(674)**	**(4,465)**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire:		
	(a) entities	–	–
	(b) tenements	–	–
	(c) property, plant and equipment	(799)	(1,772)
	(d) exploration & evaluation (if capitalised)	–	–
	(e) investments	–	–
	(f) other non-current assets	–	–
2.2	Proceeds from the disposal of:		
	(a) entities	–	–
	(b) tenements	–	–
	(c) Producing properties including property, plant and equipment (net of transaction costs)	3	3
	(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 - (lodgement) or redemption of security deposits	–	–
2.6	**Net cash from / (used in) investing activities**	**(796)**	**(1,769)**

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	(2)	(2)
3.5	Proceeds from borrowings	1,000	1,000
3.6	Repayment of borrowings	(1,167)	(2,292)
3.7	Transaction costs related to loans and borrowings	(195)	(195)
3.8	Dividends paid	–	–
3.9	Other (principal elements of lease payments)	(101)	(241)
3.10	**Net cash from / (used in) financing activities**	**(465)**	**(1,730)**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	15,618	21,647
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(674)	(4,465)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(796)	(1,769)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(465)	(1,730)
4.5	Effect of movement in exchange rates on cash held	–	–
4.6	**Cash and cash equivalents at end of period**	**13,683**	**13,683**

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]	13,683	15,618
5.2	Call deposits	–	–
5.3	Bank overdrafts	–	–
5.4	Other (cash on hand)	–	–
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**13,683**	**15,618**

[1] *Includes the Group's share of Joint Venture bank accounts (Current Quarter $1,066,084, Previous Quarter $2,137,521), and cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (Current Quarter $2,231,842, Previous Quarter $2,601,894).*

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	444
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	41,442	30,442
7.2	Credit standby arrangements	–	–
7.3	Other (please specify)	–	–
7.4	**Total financing facilities**	41,442	30,442

7.5	**Unused financing facilities available at quarter end**	11,000

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 partially amortising term loan maturing 30 September 2025 with quarterly principal and interest repayments. The interest rate at the end of the current quarter is 8.76% (floating interest rate). Of the unused facility, $5 million may be drawn at any time prior to 31 December 2023 for the purposes of funding development activity and working capital. Access to the remaining $6 million is conditional on the financier being satisfied that Central's capital commitments under agreed development plans and exploration projects are fully-funded from available facilities and expected operating cash flows for the term of the facility.

8.	**Estimated cash available for future operating activities**	**$A'000**
8.1	Net cash from / (used in) operating activities (Item 1.9)	(674)
8.2	Capitalised exploration & evaluation (Item 2.1(d))	–
8.3	Total relevant outgoings (Item 8.1 + Item 8.2)	(674)
8.4	Cash and cash equivalents at quarter end (Item 4.6)	13,683
8.5	Unused finance facilities available at quarter end (Item 7.5)	11,000
8.6	Total available funding (Item 8.4 + Item 8.5)	24,683
8.7	**Estimated quarters of funding available (Item 8.6 divided by Item 8.3)**	**36.62**

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

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

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

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

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: 31 January 2023..

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.