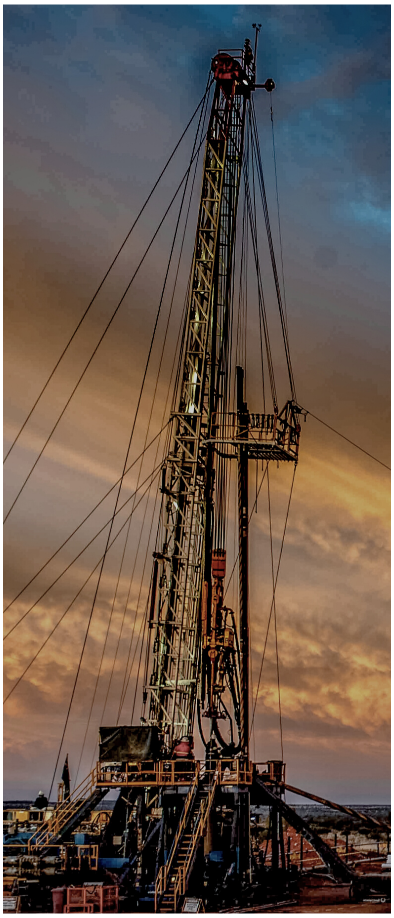
2021



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Central Petroleum Limited

Annual Report

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Front cover: Drilling at Range-7, April 2021; Maintenance at the Dingo gas processing facility, Brewer Estate, December 2020; Water Truck at WM27, July 2021; and operations at the Mereenie Central Treatment Plant (CTP)
Back cover: Drilling at Range-7, April 2021; Equipment at the Mereenie CTP; Aerial view of the Mereenie CTP and associated facilities; and drilling at WM27, July 2021

CHAIR'S LETTER

Dear Shareholders

When I wrote to shareholders in February this year with Central's half year report, we had regained some momentum following the market disruptions of 2020 and had set the foundations for the implementation of a series of important growth initiatives.

I am pleased to report that we are making good progress on these initiatives:

- Our three-well Range CSG pilot has been drilled and testing is underway, together with progressing two additional step-out wells, as we work towards a final investment decision.
- In the Northern Territory, we have recompleted four wells and drilled two new production wells which will soon be commissioned, increasing production capacity and underwriting new gas sale contracts.
- Our two-well exploration program in the Northern Territory is gathering momentum for an October start, with equipment being staged for use. If successful, Central could significantly increase its gas reserves from these targets and provide a catalyst for increased gas sales into the east coast gas market.

Strategically, a partial sell-down of our interest in the Amadeus Basin producing assets to New Zealand Oil & Gas (NZOG) and Cue Energy Resources (Cue) is tracking towards completion and was a significant milestone, crystalising the value that has been created in those fields in recent years and supporting an increased focus on implementing new growth initiatives.

Energy markets have continued to strengthen from their lows in early 2020, and with the Federal Government promoting the importance of natural gas through its Energy Plan announced during the year, gas is set to continue playing an important role in Australia's transition towards reliable low-carbon energy.

We are determined to play an increasing role in Australia's energy future by executing our growth strategy, and this will require significant investment in new projects.

Our investment in recent years has been focussed on increasing production capacity from our dependable, long-producing fields in the Amadeus Basin to meet the commissioning of the Northern Gas Pipeline in 2019. Production from those fields tripled between 2017 and 2020 as a result of our successful gas acceleration program, and we have now taken the opportunity to recycle some of this increased value back into new growth programs through the partial sell-down to NZOG and Cue.

The introduction of NZOG and Cue will result in over $100 million of investment in these fields in the next two years, allowing Central to divert more of its resources to its other potentially high-yielding, growth-orientated opportunities in the Amadeus, Surat and beyond.

The Amadeus Basin remains significantly underexplored and Central will now refocus on unlocking some of its resources from our extensive holdings in the area.

In recent times, there has been much debate about the future of fossil fuels, and we believe Central can play an important role in the transition to a cleaner energy future. Compared to coal, our natural gas is a lower-emitting transitional fuel and is likely to be in demand as a reliable energy source for many years to come.

The value of our portfolio, however, is not limited to hydrocarbons. Relatively high concentrations of valuable, and much sought after, Helium have been measured at some of our exploration wells, as have traces of naturally occurring Hydrogen, which many perceive as the next carbon-free energy source. These other non-hydrocarbon gases potentially have significant value, and our future exploration programs will seek to confirm their prevalence in the Amadeus Basin.

Across our operations our environmental footprint remains relatively small. Our gas contains low concentrations of CO_2 that does not need to be extracted or discharged. We use proven conventional drilling techniques to extract our gas and our planned development and exploration programs do not require fracking.

We continue to value the long-term relationships with our local stakeholders, Traditional Owners and landholders in the areas in which we operate, providing employment and business opportunities in these local communities, while protecting the environment in which they live. I thank them for their continued support.

I will also take a moment to reflect on some of our other achievements this year. Importantly, regarding our financial performance, our underlying earnings before interest, tax, depreciation and exploration costs (EBITDAX), at $26.1 million were 4% higher than that of the previous year. This was a solid result on lower production volumes, and our closing cash balance of $37.2 million has us in a strong position from which to progress our growth strategies.

At a Board level, we have taken the opportunity to complement the existing suite of skills, welcoming Stephen Gardiner as a Director. He brings extensive finance experience to the Board at a critical juncture in our growth strategy. We also farewelled Director Julian Fowles and long-standing Director and interim Chair, Wrix Gasteen. We thank them for their service during Central's transformation.

I thank our CEO Leon Devaney and his team at Central for their efforts over the last year in ensuring our supply to customers was not disrupted by the pandemic, for continuing our excellent safety record, for the ongoing work on the new wells and exploration initiatives, and for their efforts in bringing the asset sale towards completion.

Our strategy now is very clear: to unlock the resources in our portfolio and bring them to market. The foundations have been set and we look forward to sharing our success with our shareholders as we deliver on our plans in the coming year.

Thank you,

Mick McCormack, Chair

21 September 2021

CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders

I'm pleased to release Central's FY2021 Annual Report which demonstrates solid financial foundations and significant progress in our various growth initiatives.

We executed the partial sale of our Amadeus Basin producing assets which has released capital for the Company without diluting shareholders during very challenging market conditions. The estimated book profit of circa $35 million[1] reflects the value that we have created from our asset portfolio and is a great investment outcome for shareholders given the assets were only acquired about six years ago with very little equity.

The transaction is a vital pillar of our growth strategy, allowing us to re-invest profits back into near-term growth projects. This will accelerate growth in the broader Amadeus Basin, with the transaction stimulating over $100 million of gross investment in Central's producing assets without further cash investment required from Central. The results of this fully funded activity will become increasing visible to the market over the next year.

We have not been idle while the transaction process has run its course. Four wells have already been recompleted and two new production wells have been drilled to significantly boost Mereenie's wellhead capacity to over 40 TJ/d (Mereenie gross JV) up from the 31 TJ/d average produced last quarter. We are also excited to have seen good gas shows from the Stairway Sandstone, supporting new appraisal that could ultimately convert the Stairway's 108 PJs in 2C resources (gross JV) to 2P reserves. Given the brownfield economics, incremental production from the Stairway could have a material impact on Mereenie's production and field economic life.

We also progressed two new exploration wells at the Palm Valley and Dingo gas fields which are fully funded through the sale transaction. With equipment ordered and in transit, we remain on schedule to start drilling in Q4 of this year.

These two deep exploration wells have the potential to more than replace Central's divested reserves within the existing producing fields. They are target horizons located under established infrastructure and both formations are known to produce gas elsewhere in the Amadeus Basin. Success would provide a strong catalyst to open up further conventional gas plays across the basin and complement our efforts to pursue the next phase of new targets in 2022.

We are also focussed on progressing our other larger, potentially company-changing sub-salt targets in the Amadeus Basin which, in addition to hydrocarbons, have the potential for commercial quantities of high-value Helium and Hydrogen. Planning for an initial seismic acquisition at Zevon later this year is well advanced and has attracted a grant from the NT Government.

We also continue to engage constructively with our JV partner and permit Operator (Santos) for progress at our Dukas prospect with a larger 45% stake (up from 30%).

Success in our exploration programs could be the catalyst for development of a new route to gas-short southern markets. Our agreement with Australian Gas Infrastructure Group to be a foundation customer of a proposed new gas pipeline from the Amadeus Basin to Moomba provides line of sight for a more direct, cost-effective route to the deeper gas markets of the eastern seaboard.

In the Surat Basin, our three-well Range pilot has been drilled, completed and is already flowing small volumes of gas. The pilot will provide key production data for the front-end engineering and design work necessary to reach a final investment decision for the Range Gas Project. With initial water rates from the pilot lower than anticipated, we are moving quickly to drill two additional step-out wells to accelerate our technical understanding of the field prior to taking FID. The joint venture is currently targeting FID around March 2023, with the commencement of first gas anticipated two years after the FID date. We remain fully committed to Range, which we see as a valuable gas project with 135 PJ of 2C contingent gas resource that will become more visible to equity markets as we continue to progress toward FID.

Our financial performance in FY2021 places us in a strong position to pursue these growth strategies. Cash balances of $37.2 million were on hand at 30 June, boosted by the proceeds from the pre-sale of 3.5 PJ of gas for delivery in 2022/2023. Net debt was reduced by 32% to $31.3 million, which we expect to improve further when we pay-down $30 million of debt upon completion of the NZOG/Cue transaction.

Underlying EBITDAX improved by 4% to $26.1 million, reflecting the benefits of our cost-reduction programs which offset the lower revenues (down 8% on FY2020) driven by lower sales volumes (down 17%). The current commissioning of the new Mereenie production wells will mitigate this natural field decline in FY2022.

While our cash flows and revenues will be lower following our recent asset sell-down, the investment in new production and exploration opportunities has the potential to unlock and create new value from our portfolio, particularly as we progress toward drilling our two exploration targets, identifying a drillable prospect at Zevon and taking FID at Range.

I would like to take this opportunity to thank our dedicated staff for safely, effectively and efficiently operating our business throughout the year. I also wish to thank our many stakeholders for their continued support through a year that has presented a number of macro and sector challenges.

With a strong foundation and many of our growth initiatives already underway, we are well placed to deliver on these in FY2022 and we look forward to sharing our progress in the coming year.

Leon Devaney

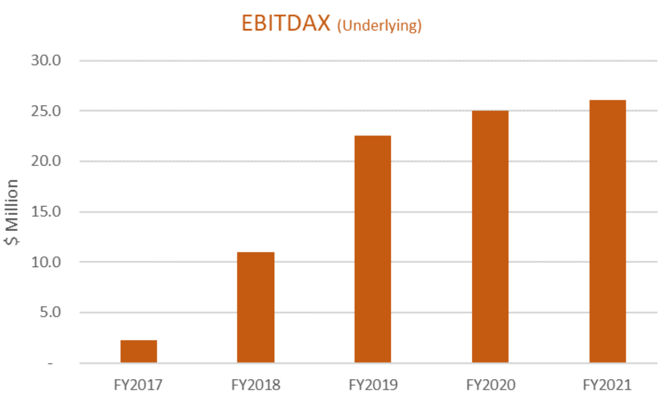
Leon Devaney, CEO
21 September 2021

[1] Subject to a final determination of the completion adjustment and movements in liabilities associated with the Sale Assets between the effective date and actual completion date.

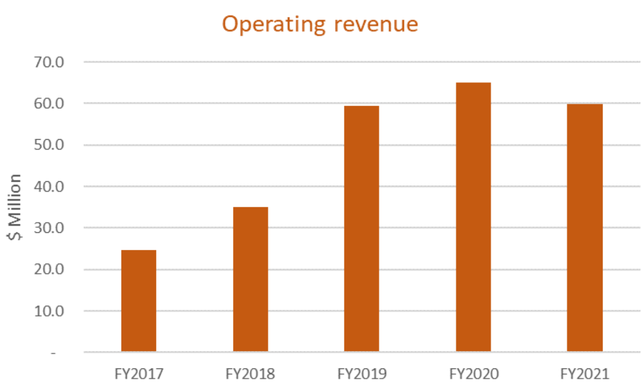
OPERATING AND FINANCIAL REVIEW

OPERATING HIGHLIGHTS

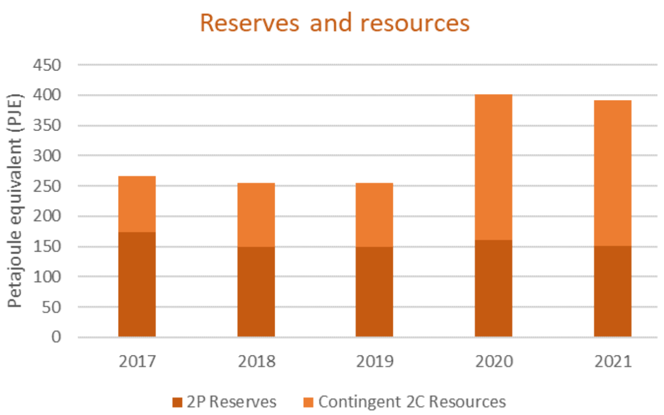
- Strong annual sales volumes and revenues:
    - Volumes 10.3 PJe
    - Revenues $59.8 million
- EBITDAX of $26.1 million.
- Full year profit of $0.3 million.
- Reduced net debt by 32% to $31.3 million and extended loan facility by 12 months to late 2022.
- Announcement of a binding agreement to sell down 50% of working interests in Amadeus Basin Producing Assets to help accelerate exploration, appraisal and development activity across the fields. Central to retain Operatorship of all fields.
- Successfully drilled a three well pilot program at the Range CSG Project and commenced testing.
- Recompleted four wells and commenced drilling the first of two new production wells at the Mereenie field.
- Announced an MOU with Australian Gas Infrastructure Group (AGIG), to participate as a foundation customer to progress towards a final investment decision on a proposed major new pipeline that would enable Central's gas to be transported direct to the Moomba gas supply hub and the larger south-eastern Australian gas markets with significantly greater cost efficiencies.
- Strengthened the Board with the appointment of Mr Mick McCormack as Chair and Mr Stephen Gardiner as a Director, both highly respected industry leaders with proven experience in the energy sector.



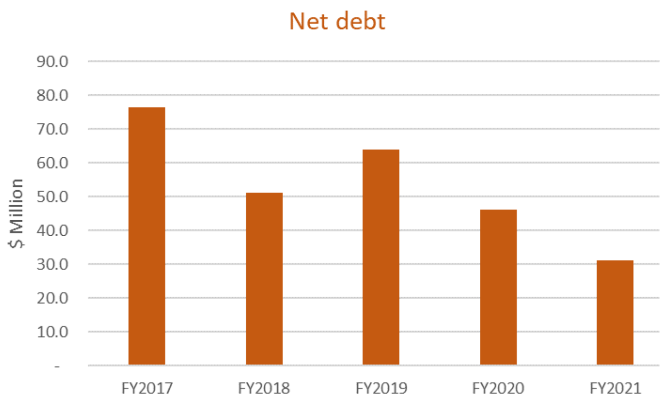
Underlying EBITDAX: Increased 4% to $26.1m in FY2021
(Earnings before interest, tax, depreciation, impairment, exploration costs, and profit on asset disposals)



Operating revenue: Decreased 8% to $59.8m in FY2021



Reserves & Resources decreased from production to 151.7 PJe



Net Debt: decreased by 32% to $31.3 million at 30 June 2021

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a profit after income tax for the year ended 30 June 2021 of $0.3 million (2020: $5.4 million).

The above result was after expensing exploration costs of $7.7 million (2020: $5.3 million). The Group's policy is to expense all exploration costs as incurred.

The table below shows key metrics for the Group:

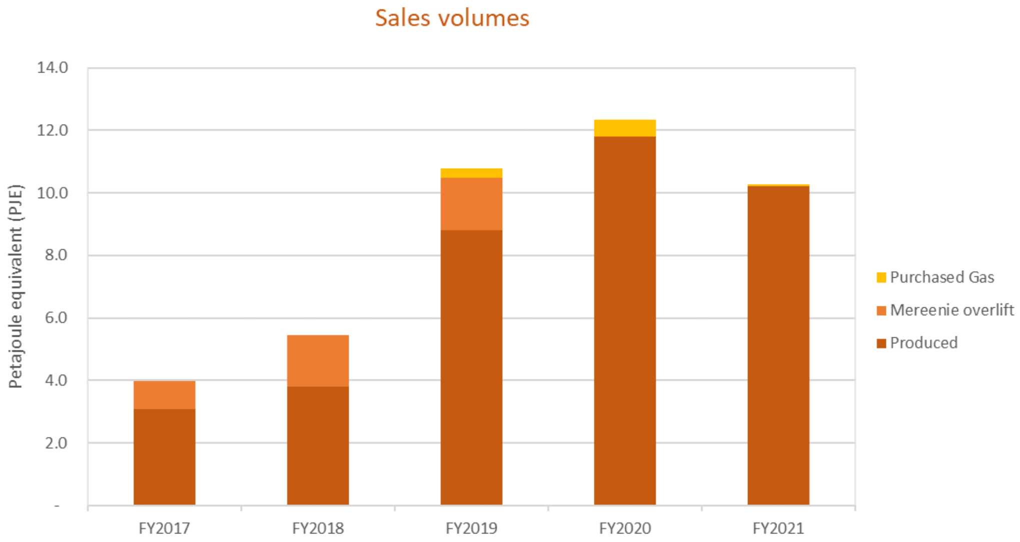
Key Metrics	Total 2021	Total 2020	Change	% Change
Net Sales Volumes				
- Natural Gas (TJ)	**9,820**	11,822	(2,002)	(17)%
- Oil & Condensate (bbls)	**77,255**	89,016	(11,761)	(13)%
Sales Revenue ($'000)	**59,827**	65,046	(5,219)	(8)%
Gross Profit ($'000)	**30,975**	31,660	(685)	(2)%
Underlying EBITDAX[1] ($'000)	**26,088**	25,010	1,078	4%
Underlying EBITDA[2] ($'000)	**18,349**	19,733	(1,384)	(7)%
Underlying EBIT[3] ($'000)	**5,846**	3,299	2,547	77%
Underlying profit/(loss) after tax[4] ($'000)	**251**	(2,982)	3,233	108%
Statutory profit after tax ($'000)	**251**	5,411	(5,160)	(95)%
Net cash inflow from Operations[5] ($'000)	**24,136**	15,727	8,409	53%
Capital expenditure[6] ($'000)	**11,792**	2,857	8,935	313%

1 Underlying EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs and profit on disposal of exploration permits (refer reconciliation below).
2 Underlying EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and profit on disposal of exploration permits.
3 Underlying EBIT is Earnings before Interest, Tax and profit on disposal of exploration permits.
4 Underlying profit / loss after tax is statutory profit after tax, before profit on disposal of exploration permits.
5 Cashflow from Operations includes cash outflows associated with Exploration activities. 2021 includes the proceeds from pre-sold gas.
6 Capital expenditure on tangible assets.

Reconciliation of statutory profit before tax to underlying EBITDAX	2021 $'000	2020 $'000
Statutory profit before tax	251	5,411
Profit on disposal of exploration permits	-	(8,393)
Underlying profit/(loss) before tax	**251**	**(2,982)**
Net finance costs	5,595	6,281
Underlying EBIT	**5,846**	**3,299**
Depreciation and amortisation	12,503	16,257
Impairment	—	177
Underlying EBITDA	**18,349**	**19,733**
Exploration expenses	7,739	5,277
Underlying EBITDAX	**26,088**	**25,010**

Sales Volumes

Sales volumes were 17% lower than FY2020 at 10.3 PJe, reflecting weaker markets in the first half and natural field decline throughout the year, although supported by the Company's portfolio of firm long-term gas supply contracts. Two new production wells to be commissioned at Mereenie by October 2021 are expected to increase overall wellhead capacity to over 40 TJ/d.



Note: Oil converted at 5.816 GJ/bbl.

Sales Revenue

Central recorded sales revenue of $59.8 million, down 8% on FY2020, reflecting the lower sales volumes. Realised prices were up 11% on FY2020 at $5.83/GJe as global oil prices and domestic gas markets recovered from the lows experienced in early 2020.

Gross Profit

Despite the 17% decline in sales volume, gross profit from operations declined by just 2% year on year. On a per unit basis, production costs were only 3% higher, benefiting from strategies to manage costs to deliver cost-effective operations, including a reduction in staff back to 2017 levels.

Other Income

Other income was $8.5 million lower than FY2020 which included $7.7 million as final settlement for the transfer of a 50% interest in the Range Gas Project and $0.68 million profit on the transfer of exploration tenements. To assist with comparability of this year's result, we have reported EBITDAX, EBITDA and EBIT against the underlying results in FY2020, which exclude the gains of $8.4 million.

Depreciation and Amortisation

Non-cash depreciation and amortisation costs decreased from $16.3 million to $12.5 million, reflecting the decrease in production and lower depreciable asset base.

Net Assets/Liabilities

At 30 June 2021, the Group had a net asset position of $3.7 million, an improvement on FY2020 due to the net profit for the year before share based payments.

Included in liabilities on the Group's balance sheet are amounts recognised in respect of deferred revenue associated with pre-sales and make-up gas provisions amounting to $20.9 million (excluding $20.9 million which will be transferred to the incoming joint venturers and reclassified as held for sale). These liabilities will be transferred to revenue as gas is supplied to the customer or forfeited to Central under take-or-pay contracts and therefore do not represent a cash liability to the Group. Upon completion of the sell down of its producing assets, the Group will make circa $30 million in repayments of its debt facility with Macquarie Bank.

OPERATING AND FINANCIAL REVIEW

Debt

Net debt reduced by 32% to $31.3 million at 30 June 2021. EBITDAX of $26.1 million covered (3.3x) service of loan facilities of $7.9 million. The outstanding balance of the loan facility at 30 June 2021 was $66.8 million, with $36.0 million due for repayment in FY2022, including the lump sum repayment to be made from the proceeds of the asset sell down when it completes.

The consolidated debt ratio at 30 June 2021 improved to 0.39 (2020: 0.45). Debt ratio is defined as: Total Debt/Total Assets. Net gearing at 30 June 2021 was 27% (2020: 44% or 36% if re-based to 30 June 2021 market capitalisation). Net gearing is calculated as: Net Debt / (Market capitalisation + Net Debt). Debt service is supported by long term gas sales contracts and the Group's certified oil and gas reserves.

Net Cash Flow

Cash balances increased by $11.2 million over the year. Net cash flow from production operations for 2021 was $37.7 million compared to $29.0 million for 2020, with the increase reflecting the proceeds from the presale of gas in FY2021, partly offset by lower revenue net of operating expenses and gas purchases.

After payment of $3.9 million of interest costs, $4.2 million of corporate expenses (net of government incentives) and $5.5 million for exploration activities, net cash flow from operating activities was $24.1 million, up from $15.7 million in 2020. Exploration expenditure in FY2021 was $2.3 million higher than FY2020, reflecting additional expenditure on the Amadeus exploration program and Range pilot program and other pre-FID activities.

The net cash surplus from operating activities was partly directed towards $4.8 million of borrowing repayments and $8.0 million was invested in sustaining capital works, new production wells and security deposits.

Five Year Comparative Data

The following table is a five-year comparative analysis of the Consolidated Entity's key financial information. The balance sheet information is as at 30 June each year and all other data is for the years then ended.

	2017 $ MILLION	2018 $ MILLION	2019 $ MILLION	2020 $ MILLION	**2021 $ MILLION**
Financial Data					
Operating revenue	24.79	34.94	59.36	65.05	**59.83**
Exploration expenditure	1.90	8.79	15.80	5.28	**7.74**
Profit/(loss) after income tax	(24.73)	(14.08)	(14.53)	5.41	**0.25**
EBITDAX	2.22	11.01	22.19	33.40	**26.09**
Underlying EBITDAX	2.22	11.01	22.19	25.01	**26.09**
Equity issued during year	—	25.47	—	—	**—**
Property, plant and equipment[1]	106.82	103.85	123.48	107.85	**108.28**
Cash[1]	5.48	27.22	17.81	25.92	**37.17**
Borrowings	(82.17)	(78.33)	(81.73)	(70.77)	**(66.81)**
Net Assets (Total Equity)	(5.96)	7.06	(5.62)	1.58	**3.69**
Net Working Capital (Net current assets/(liabilities))	0.73	17.19	(1.53)	6.75	**8.25**

[1] *Includes assets classified as held for sale*

	2017	2018	2019	2020	**2021**
Operating Data					
Gas Sales (TJ)	3,322	4,842	10,229	11,822	**9,820**
Oil Sales (barrels)	111,380	105,619	97,392	89,016	**77,255**
No. of employees at 30 June	83	89	99	92	**85**

OPERATIONS AND ACTIVITIES

Central Petroleum Limited is an emerging ASX-listed oil and gas producer, with a portfolio of producing and prospective tenements across the Northern Territory (NT) and Queensland. Central is the operator of the largest onshore gas producing fields in the NT, supplying industrial customers, electricity generators and senior gas distributors from three producing fields near Alice Springs.

Having increased production from its NT fields three-fold since 2017, Central is now focussed on a new multi-faceted growth strategy:

- Increasing production capacity from its existing fields. Two new production wells will be online at Mereenie by October 2021;
- Developing the Range CSG project in Queensland's productive Surat Basin. The pilot is currently producing gas and a final investment decision around March 2023 is being targeted, with the commencement of first gas anticipated two years later;
- Near-term exploration targeting additional gas resources at Central's NT producing fields. Two new wells will be drilled, starting late 2021. Others are planned for 2022; and
- Exploration targeting larger multi-Tcf sub-salt targets in the Amadeus Basin which are also prospective for Helium and Hydrogen.

Central is also working with Australian Gas Infrastructure Group (AGIG) to progress the proposed Amadeus to Moomba Gas Pipeline to a FID. The proposed pipeline promises to provide a more direct, cost-efficient route to eastern gas markets.

Through its existing production base, new development projects and enormous exploration potential, Central is well-positioned to play an increasing role in Australia's energy future.

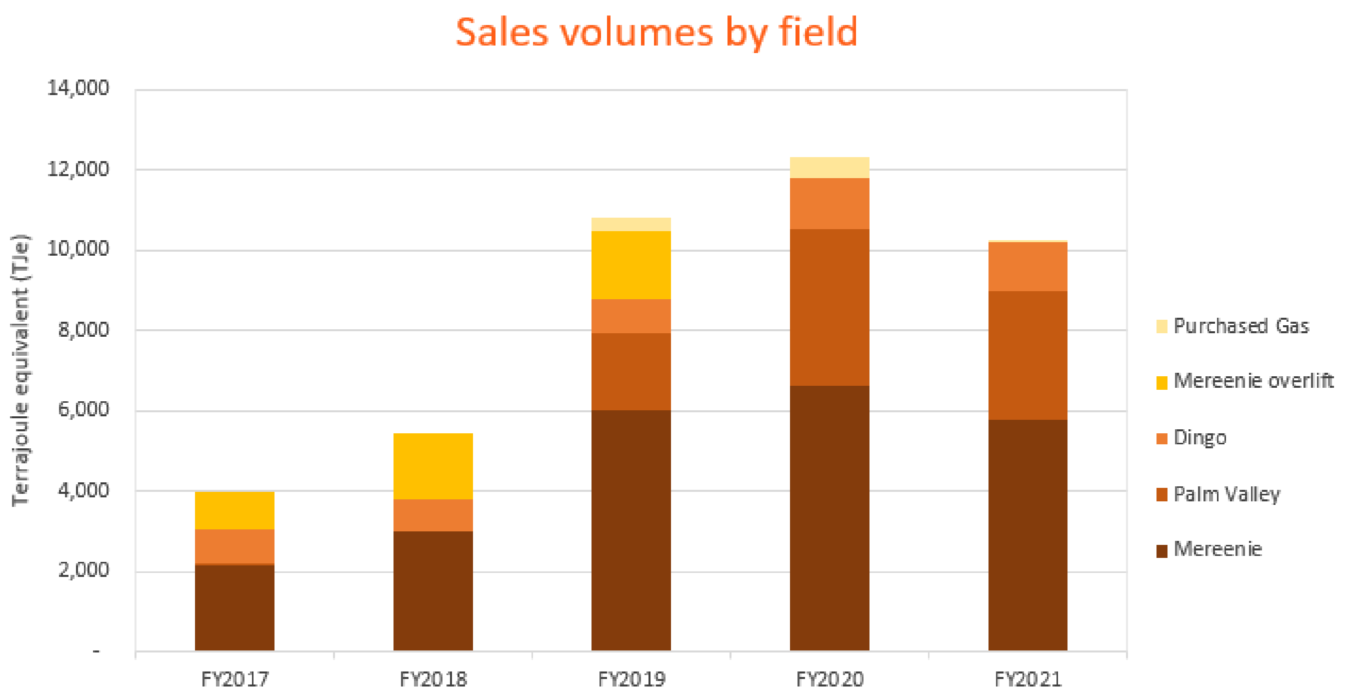
Producing Assets

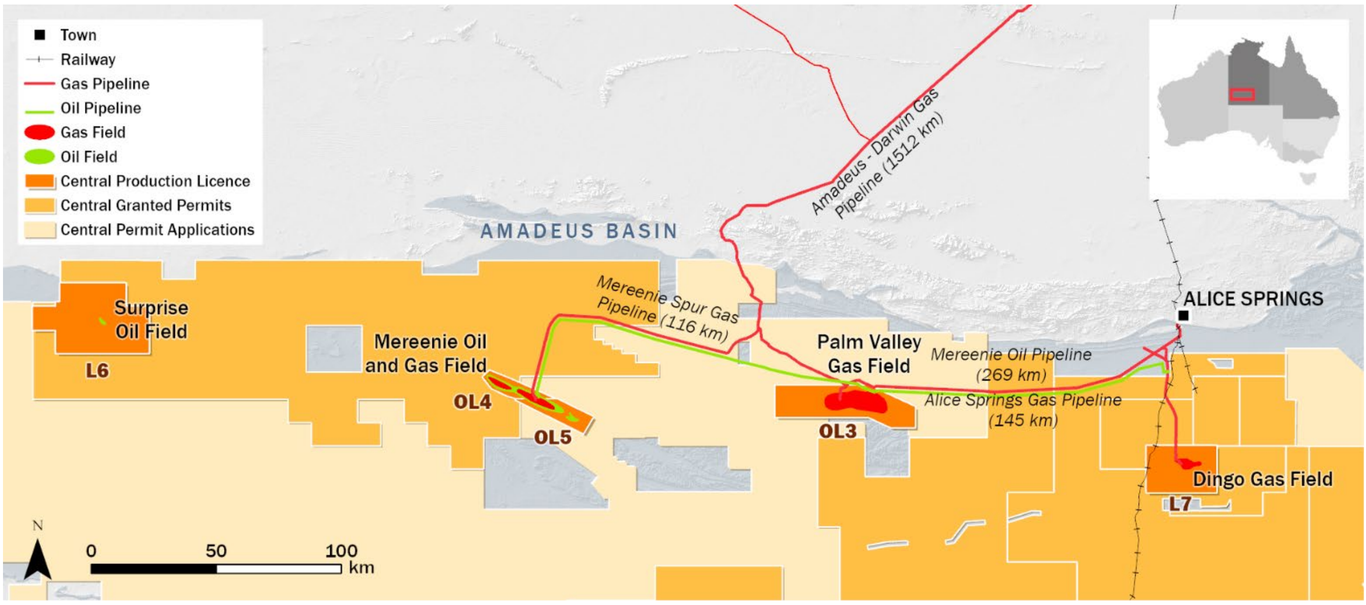
Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2021	FY 2020
Gas	PJ	9.8	11.8
Crude and Condensate	bbls	77,255	89,016
Total	**PJe**	**10.3**	**12.3**

Note: Oil is converted to Petajoule equivalent (PJe) at 5.816 GJe/bbl.

Sales volumes were 17% lower than FY2020 at 10.3 PJe, reflecting weaker gas markets in the first half of the financial year and natural field decline in advance of the commissioning of new production wells by October 2021.





Location of Central's producing oil and gas fields

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory
(Central—50% Interest (Operator)[1], Macquarie Mereenie Pty Ltd—50% Interest)

Sales volumes (Central share)	Unit	FY 2021	FY 2020
Gas	PJ	5.3	6.1
Crude and Condensate	bbl	77,255	89,016

Reserves & Resources (Central share)[2]	Unit	1P	2P	2C
Gas	PJ	64.7	87.2	91.2
Oil	mmbbl	0.69	0.89	0.10

1 Central's interest will reduce to 25% upon completion of the asset sale which is expected to settle on 1 October 2021.
2 Reserves and resources are as at 30 June 2021. 2C gas resources include 54 PJ attributable to the Stairway Formation (refer Appraisal Assets - Amadeus Basin section of this report). Central's share of Mereenie reserves and resources will reduce by approximately 50% upon completion of the asset sale, which is expected to settle on 1 October 2021.

The Mereenie oil and gas field was discovered in 1963 and commenced production in 1984, delivering hydrocarbon liquids for sale in South Australia and gas to Northern Territory markets. A significant expansion program was undertaken to lift firm plant capacity to 44 TJ/d capacity in time to supply gas to the east coast market through the Northern Gas Pipeline (NGP) in January 2019.

The Mereenie hydrocarbon accumulation is contained in an elongated 4-way dip anticline that has a length of 40 km and width of more than 5 km. The reservoirs comprise a series of thin stacked sandstones of the Pacoota Formation, which have been the focus of development to date. This development has targeted both gas production and oil production from an oil rim. The overlying Stairway Sandstone has not been materially developed to date, but it represents significant upside potential as the Stairway Formation has produced gas in several wells.

Gas production averaged 29.5 TJ/d over the year, down from the 33 TJ/d produced in FY2020. During the first half of FY2021, production averaged 28.5 TJ/d as markets recovered from the sharp downturn experienced in early 2020. Gas production increased to 30.5 TJ/d in the 2nd half, close to the well capacity of approximately 31 TJ/day at 30 June 2021.

To offset ongoing natural field decline, four existing wells were re-completed in the fourth quarter to access producing zones which were previously behind pipe. In addition, drilling commenced on the first of two new crestal production wells in June, with both wells expected to be commissioned by October 2021.

Palm Valley Gas Field (OL3)

Northern Territory
(Central—100% Interest)[1]

Sales volumes (Central share)	Unit	FY 2021	FY 2020
Gas	PJ	3.2	3.9

Reserves & Resources (Central share)[2]	Unit	1P	2P	2C
Gas	PJ	21.5	24.4	13.7

1 Central's interest will reduce to 50% upon completion of the asset sale which is expected to settle on 1 October 2021.
2 Reserves and resources are as at 30 June 2021. Central's share of Palm Valley reserves and resources will reduce by approximately 50% upon completion of the asset sale, which is expected to settle on 1 October 2021.

Gas was first discovered at Palm Valley in 1965 and is primarily reservoired in an extensive fracture system in the lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone. The anticlinal structure is approximately 29 km in length and 14 km in width. The field was successfully restarted in 2018 in order to deliver gas into new gas markets made available via the new NGP connection.

The Palm Valley field performance exceeded expectations during the year, averaging 8.9 TJ/d. The PV13 well, commissioned in May 2019, is declining from its peak production plateau experienced in FY2020, but continues to outperform initial expectations. High production rates from this well are believed to be supported by ongoing recharge from the fracture network, indicating further outperformance by the well remains possible.

Following the success of the PV13 well, three further potential locations have been identified for the drilling of new lateral wells similar to PV13 in order to offset the field's natural decline. The first of these laterals is expected to be drilled from the Palm Valley Deep exploration well in early 2022 if the primary exploration target, the deeper Arumbera Sandstone proves unproductive. Other laterals could be drilled from existing wells for efficient access to additional production capacity.

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

Northern Territory
(Central - 100% Interest)[1]

Sales volumes (Central share)	Unit	FY 2021	FY 2020
Gas	PJ	1.2	1.2

Reserves & Resources (Central share)[2]	Unit	1P	2P	2C
Gas	PJ	28.0	34.9	—

1 Central's interest will reduce to 50% upon completion of the asset sale which is expected to settle on 1 October 2021.
2 Reserves and resources are as at 30 June 2021. Central's share of Dingo reserves and resources will reduce by approximately 50% upon completion of the asset sale, which is expected to settle on 1 October 2021.

Gas was discovered at the Dingo field in 1985 in the Neoproterozoic lower Arumbera Sandstone. The structure is 11 km by 5.6 km, and the productive reservoir is at a depth of approximately 3,000 metres subsurface.

The Dingo Gas Field supplies gas through a dedicated 50 km gas pipeline to Brewer Estate in Alice Springs for use in the Owen Springs Power Station.

Sales volumes were consistent with FY2020, averaging 3.3 TJ/d, meeting demand from the power station. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions under which Central will be paid in January 2022 for any gas nomination shortfall by the customer in CY2021.

The Dingo Deep exploration well is expected to be drilled in Q3 FY2022, targeting the deeper Pioneer Sandstone, which has flowed gas at the nearby Ooraminna prospect, and the Areyonga Formation. The wellhead capacity of the Dingo field is likely to be boosted even if the Pioneer and Areyonga exploration targets prove unsuccessful, as the well will be completed to access the existing producing Arumbera Sandstone for tie-in to the Dingo facilities.

Surprise Oil Field (L6)

Northern Territory
(Central—100% Interest)

The Surprise West well produced approximately 88,650 barrels of oil from March 2014 to August 2016 when it was shut in due to low oil prices and to obtain long term pressure data.

The field remains shut in. A restart may be considered following a sufficient recovery in oil markets. Environmental and reservoir monitoring continued throughout the year.

Appraisal Assets – Amadeus Basin

Mereenie Stairway (OL4 and OL5)

Northern Territory
(Central—50% Interest (Operator)[1], Macquarie Mereenie Pty Ltd—50% Interest)

Reserves & Resources (Central share)[2]	Unit	1P	2P	2C
Gas	PJ	—	—	54

[1] Central's interest will reduce to 25% upon completion of the asset sale which is expected to settle on 1 October 2021.
[2] Reserves and resources are as at 30 June 2021. Central's share of Mereenie reserves and resources will reduce by approximately 50% upon completion of the asset sale, which is expected to settle on 1 October 2021.

The recently drilled WM28 production well measured sustained gas flow rates from the Upper Stairway Sandstone of 0.6 mmscfd/d while drilling through to the deeper Pacoota producing intervals. Whilst the Stairway is typically considered to be tight, the presence of natural fractures provides sufficient permeability which can be exploited through deviated or horizontal drilling techniques (as occurs in the Pacoota at Palm Valley).

The successful flow test in the Upper Stairway provides a good indication of the presence of open natural fractures at WM28. This is consistent with fracture modelling which indicates a high likelihood of natural fractures (predominantly vertical) in the crestal region of the Mereenie field. Significant flows obtained while drilling through the Stairway have also been recorded in prior development wells, indicating there could be extensive portions of the Stairway amenable to commercial production with horizontal wells. Further Stairway appraisal would target those areas with evidence of good flows (such as WM28) to reduce the risk of encountering mineralised fractures, as was the case in the prior Lower Stairway appraisal well, WM26. Central and its joint venturers at Mereenie will consider appraisal options for the Stairway at Mereenie.

Drilling at WM27
Photo by Phil Allen

Appraisal Assets – Surat Basin

Range Gas Project (ATP 2031)

Surat Basin, Queensland
(Central - 50% Interest, Incitec Pivot Queensland Gas Ltd (IPL) - 50%)

Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	—	—	135

In addition to Central's producing oil and gas fields in the Northern Territory, Central and joint venturer, Incitec Pivot Limited, are working towards a final investment decision (FID) for the Range coal seam gas (CSG) project in Queensland's gas-rich Surat Basin.

Central was formally granted the Authority to Prospect (ATP) 2031 in August 2018. The 77km^2 block is strategically located in the heart of Queensland's CSG province which hosts thousands of wells producing from the same coal measures at similar depths.

In 2019, following a successful four well exploration program, 270 PJ of 2C contingent gas resource were certified (Central share 135 PJ) within the three coal seams. The wells confirmed 30m of average net coal thickness and permeability in line with or better than expectations. The proven production capacity of the coals in surrounding areas gives Central a high degree of confidence that the 2C resources can be converted into 2P gas reserves to support a final investment decision.

Range pilot

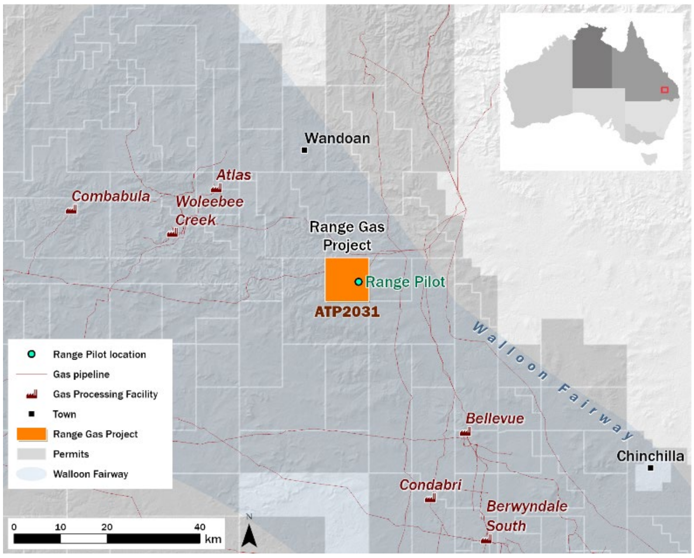
A three well pilot was drilled in April 2021 and is being production tested for several months to provide key subsurface and production data. The three Range pilot wells, Range-6, Range-7 and Range-8 were successfully drilled to depths of between 675m and 685m, with net coal of between 26m and 28m across the three coal seams of the Walloon Coal Measures.


Range pilot site

The Range pilot consists of three wells closely spaced at 200m apart, a production water tank, flare and associated pipework. Each well has been completed with a slotted liner over the three seams of the Walloon Coal Measures with a downhole pump installed.

Testing of the pilot commenced in mid-June and will provide production data for several months to support a FID. The pilot 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.

Gas breakthrough was observed immediately upon commencement of pumping—earlier than expected—indicating the presence of coals that are fully saturated with gas. The water level in the wells was gradually drawn-down to the pumps and by mid-August aggregate daily gas rates had reached around 50,000 scfd. These are expected to increase as dewatering continues.



Location of the Range Gas Project (ATP 2031) and pilot in relation to other coal seam gas projects in the Surat Basin

Initial aggregate water rates are lower than anticipated which implies less capital will be required for water handling, processing and disposal in the development phase. On the downside, an extended pilot dewatering period is likely to be required. To accelerate technical understanding of water and gas production profiles for FID, the pilot will be expanded with two new step-out wells (Range 9 and 10) in late 2021. The new pilot step-out wells will be spaced at a greater distance than the original pilot wells and tied into the existing water tank.

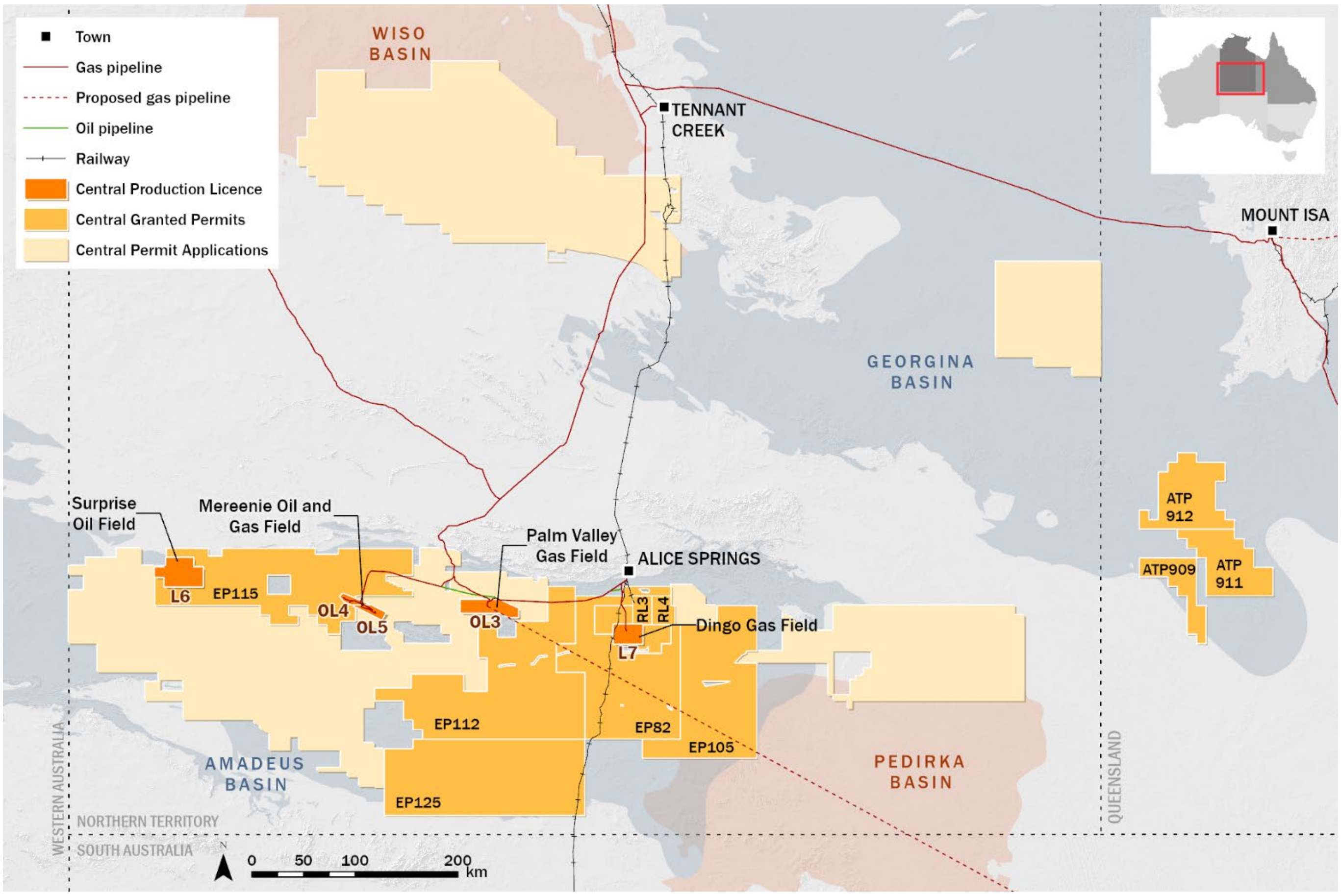
In parallel with the pilot activities, applications for key State and Federal approvals are progressing for the planned full field development. Proposals have been received from several established infrastructure providers for provision of gas processing facilities for the full field development.

Gas production from the Range Gas Project is reserved for domestic use. The joint venture is targeting FID around March 2023, with the commencement of first gas anticipated two years after the FID date. The Range Gas Project is at the doorstep of the east coast gas market and could nearly double Central's reserve base and annual sales volumes.

Drilling at Range-7
Photo by Alan Johnson

Exploration Assets

Central Petroleum holds a significant portfolio of exploration opportunities across the Northern Territory and Queensland, including extensive positions in the long producing, yet underexplored Amadeus Basin in the NT, and frontier opportunities in the Wiso and Southern Georgina basins. The total area held by Central for exploration (both granted and under application) is 181,875 km^2 (72,197 km^2 granted and 109,678 km^2 under application).



Location of Central's Petroleum Permits, Licences and Applications in Central Australia

Amadeus Basin

Central Petroleum has significant operations within the proven Amadeus Basin, which has some of Australia's largest prospective onshore resources of conventional gas. Although the Amadeus Basin has provided reliable, high quality oil and gas since the 1980s, it is relatively under-explored and it is believed to hold significant untapped potential for decades of reliable, high volume gas supply.

In addition to proven hydrocarbons, the Amadeus basin is also prospective for Helium and Hydrogen. Exploration wells at Mt Kitty and Magee have shown high concentrations of Helium and Hydrogen in the basin. These high-value non-hydrocarbon gases are generally associated with sub-salt prospects and provide a key driver for Central in progressing future sub-salt exploration in the basin, such as at the Zevon and Dukas prospects.

The Amadeus Basin has, to date, been a focus for the majority of Central's exploration activity, with ~170,000 km^2 of areal extent, five known working petroleum systems and four fields having produced significant quantities of oil and gas.

Notwithstanding its impressive production history, the Amadeus Basin is one of the few remaining large, under-explored, working hydrocarbon systems onshore Australia, with only a total of 39 exploration wells and ~14,500 km of 2D seismic acquired across the entire basin. This historic underinvestment can in part be attributed to the lack of pipeline connections to eastern and southern markets prior to 2019 and the small Northern Territory gas market.

The Northern Gas Pipeline, commissioned in early 2019, provides a pathway to an attractive east coast gas market and the proposed Amadeus to Moomba Gas Pipeline will, if developed, provide a more direct, efficient route to deeper southern markets and is likely to provide a catalyst for increased exploration in the Amadeus Basin.

Detailed play-based exploration analysis has so far identified 115 potential targets (65 gas and 50 oil) within Central's permits and application areas in the basin. Central's exploration plans are presently centred around several high priority targets which can be drilled conventionally and without stimulation (hydraulic fracturing):

- **Immediate in-field opportunities**: Targeting 192 PJ of mean prospective gas resources (96 PJ Central share[1]), Central expects to drill two exploration wells starting in late 2021 within its existing production areas at Palm Valley and Dingo, testing deeper formations which are known to be productive elsewhere in the basin. These wells, if successful, will be able to be tied-in to existing production facilities relatively quickly and efficiently.
- **Near term opportunities**: Targeting 401 PJ of gas and 29 mmbbl of oil (mean prospective resource), the proposed Orange-3 gas appraisal well and Mamlambo oil exploration well respectively, are currently identified as lower-risk, high reward opportunities close to productive areas. In addition, recent strong gas shows while drilling through the Stairway Sandstone at Mereenie provides new technical information supporting further Stairway appraisal work. If successful, appraisal of the Stairway could ultimately convert up to 108 PJ (gross JV) of 2C resource into 2P reserves, significantly increasing production capacity and the economic life of the field.
- **Large sub-salt targets**: The Amadeus Basin contains several large, potentially multi-Tcf sub-salt targets that are also prospective for Helium and Hydrogen. Planning is underway to return to the Dukas prospect and acquire seismic at the Zevon prospect during FY2022.

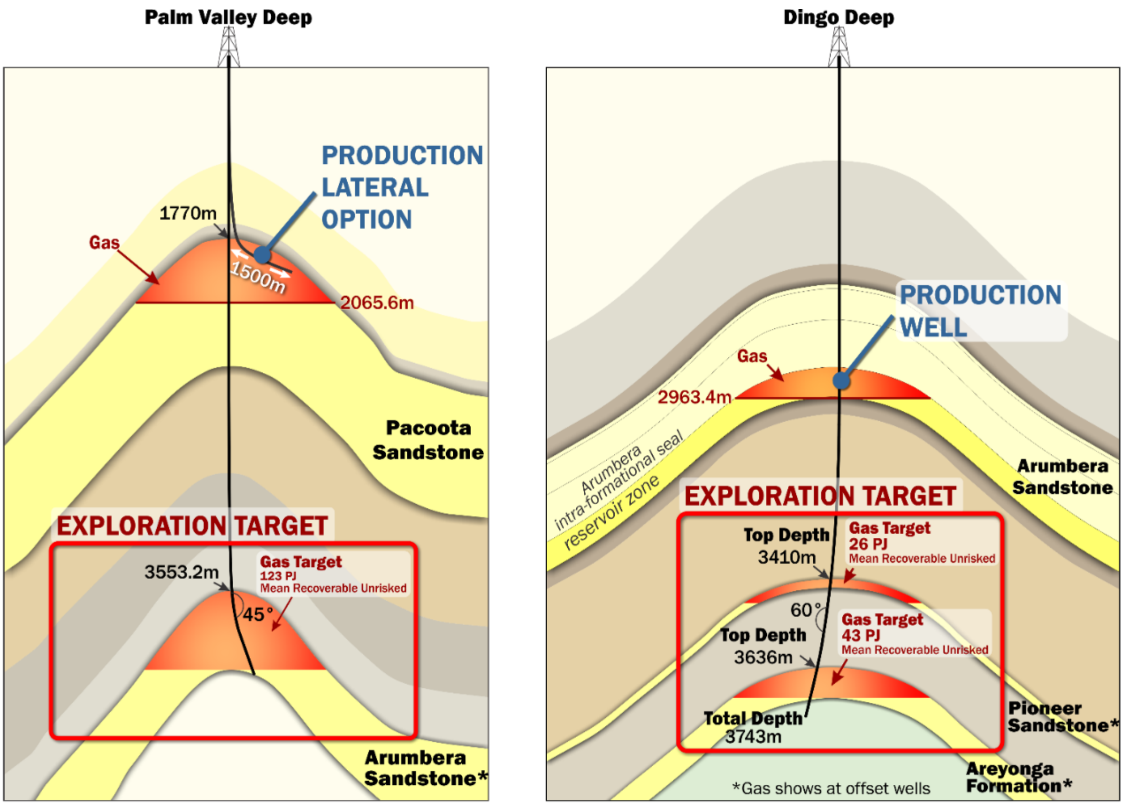
Amadeus exploration – Immediate in-field opportunities

(OL3 and L7) Amadeus Basin, Northern Territory
(Central – 100% interest)[2]

A two well exploration program is scheduled to commence in late 2021 targeting up to 192 PJ of mean prospective gas resources (96 PJ Central share[1]). The wells have compelling investment justifications, including rapid commercialisation through proximity to existing infrastructure, and attractive brownfield economics. The exploration program targets natural fractures within conventional formations.

The Palm Valley Deep and Dingo Deep wells will test deeper reservoirs which have produced gas elsewhere in the region. These wells are located within the existing Palm Valley and Dingo fields and, if successful, provide the opportunity for low-cost production via tie-in to existing infrastructure.

If the deeper targets are unsuccessful, the wells can be completed in the shallower producing formations as production wells.



Drawings not to scale, other than relative thickness for formations at well bore.

Schematics of the Palm Valley Deep and Dingo Deep exploration wells (not to scale)

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[1] After completion of the asset sale which is expected to settle on 1 October 2021

[2] Central's interest will reduce to 50% on completion of the asset sale which is expected to settle on 1 October 2021

Palm Valley Deep

The Palm Valley Deep well will target a mean prospective resource volume of 123 PJ (61.5 PJ net to Central[1]) in the deep Arumbera Sandstone (depth circa 3,500m) which is the productive interval at the Dingo field. If the deep test fails, the well will be plugged back and a 1,500m lateral production well will be drilled at the Pacoota level and completed for immediate tie-in to existing infrastructure.

Dingo Deep

The well will be located crestally in the field and target a mean prospective resource volume of 69 PJ (34.5 PJ net to Central[1]) in the deeper Pioneer Sandstone and Areyonga Formation at a depth of up to 3,700m. Both formations have had gas shows with flows to surface achieved from the Ooraminna well at the Pioneer Sandstone level. A successful exploration test will open up a new play fairway in the basin. The well will also be completed at the productive Arumbera Formation level for tie-in to the Dingo facilities.

Amadeus exploration – Near-term opportunities

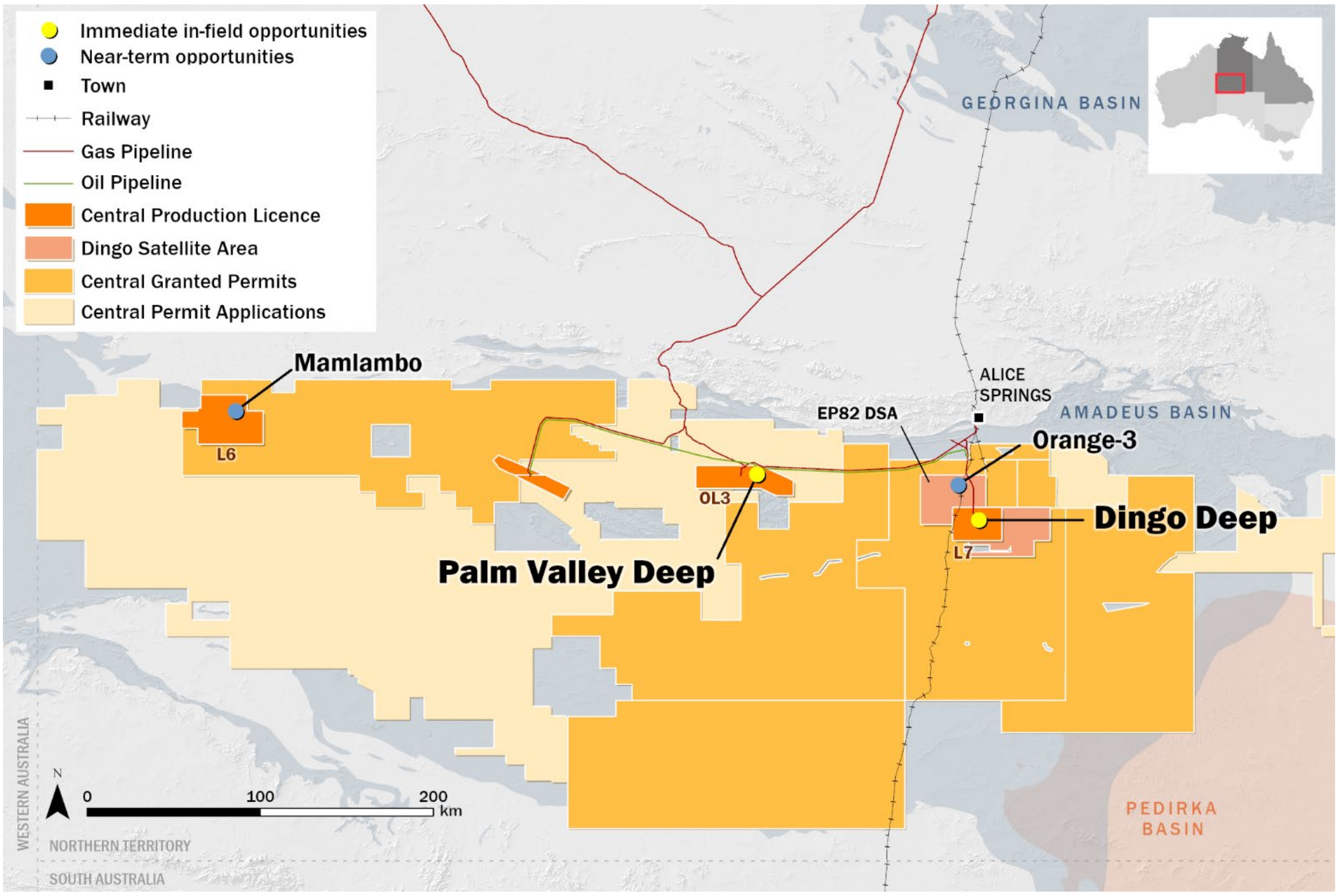
Amadeus Basin, Northern Territory

Central has identified several other promising lower-risk, high reward exploration targets close to productive areas which it intends to pursue in the near term. The targets include:

Orange-3 (EP82 DSA), targeting a mean prospective gas resource of 401 PJ: The Orange-3 well will target the Arumbera Sandstone, which is the producing zone at the Dingo field, some 23km to the south-east. The well will also target the deeper Pioneer Sandstone and Areyonga Formation which are volumetrically significant and close to the existing Dingo pipeline. Results from the Dingo Deep well, which is targeting the same deeper structures could influence the timing of drilling Orange-3. Total depth for the well is planned at 3,800m.

Mamlambo (L6), targeting a mean prospective resource of 29 mmbbl of oil: The proposed Mamlambo well is a large structure defined on an existing seismic grid, only 8km from the Surprise oil field. The well is targeting the Lower Stairway Sandstone and the Pacoota Formation, both of which are proven reservoirs in the Surprise and Mereenie oil and gas fields. Total planned depth for the well is 1,300m.

Although no final investment decision has been made, permitting, approvals and planning for the Orange and Mamlambo wells is well advanced.



Location map of immediate in-field exploration opportunities

[1] After completion of the asset sale which is expected to settle on 1 October 2021

Lead / Prospect	Unit	Prospective Resource[1] Best estimate (P50)	Mean
Immediate in-field opportunities – drilling 2021			
Dingo Deep	PJ	24.5	**34.5**
Palm Valley Deep	PJ	37.5	**61.5**
Aggregate total immediate in-field opportunities	**PJ**	**62.0**	**96.0**
Near-term opportunities			
Orange-3	PJ	284.0	401.0
Mamlambo (oil)	mmbbl	24.0	29.0

Central's interest in the prospective resources displayed in this table have been adjusted to reflect Central's reduced interests that would apply following completion of the asset sale announced on 25 May 2021.

1. **Prospective Resource**: As first reported to ASX on 7 August 2020. The volumes of prospective resources represent the unrisked recoverable volumes derived from Monte Carlo 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.

   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.

   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 estimate continue to apply and have not materially changed.

Amadeus exploration – Large sub-salt targets

Amadeus Basin, Northern Territory

The Amadeus Basin hosts Neoproterozoic aged sub-salt targets within the Heavitree Formation and the fractured granitic basement. The source of hydrocarbons for the sub-salt play is provided by the organic rich rocks at the base of the Gillen Formation, and the seal is provided by extensive evaporitic units of the upper Gillen Formation.

In addition to hydrocarbons, the presence of radiogenic basement rocks and an evaporitic sealing unit has created the ideal conditions for a Helium and Hydrogen play in the Neoproterozoic sub-salt section of the Amadeus Basin.

Evidence of a working system for Helium and Hydrogen is provided by gas compositions from the Mt. Kitty-1 and Magee-1 wells, which recorded 9% and 6% Helium respectively, in combination with hydrocarbon gases and Nitrogen on well test. In addition, 11% Hydrogen was recorded in Mt. Kitty-1. Helium concentrations above 1% are regarded globally as high, with a concentration of greater than 0.5% regarded as potentially economic.

A number of large leads exist within the sub-salt play within the Amadeus Basin, including the Dukas prospect in EP112 and the Zevon area in EP115. Given the potential size of these individual prospects and leads, success at any of these targets would be company changing and have the potential to unlock a significant new source of gas, Hydrogen and/or Helium for the east coast market.

Dukas (EP112)

(Central – 45% interest, Santos 55%)

Dukas is a geographically large (>400 km^2) gas prospect with multi-Tcf potential located in EP112, approximately 175 km south west of Alice Springs. The Dukas-1 exploration well was suspended at a depth of 3,704m in mid-2019 after encountering hydrocarbon-bearing gas from an over-pressured zone close to the primary target. Up to 2% Helium and 0.5% hydrogen was recovered in association with methane and nitrogen in mud gasses associated with the over-pressured zone. Although not from the reservoir section (which is yet to be encountered) this is an encouraging sign of the potential presence of these gases in the reservoir zone.

The operator, Santos, has been assessing various options to intersect the target formation using specialised high-pressure equipment. A decision on the forward plan for Dukas is expected in late 2021.

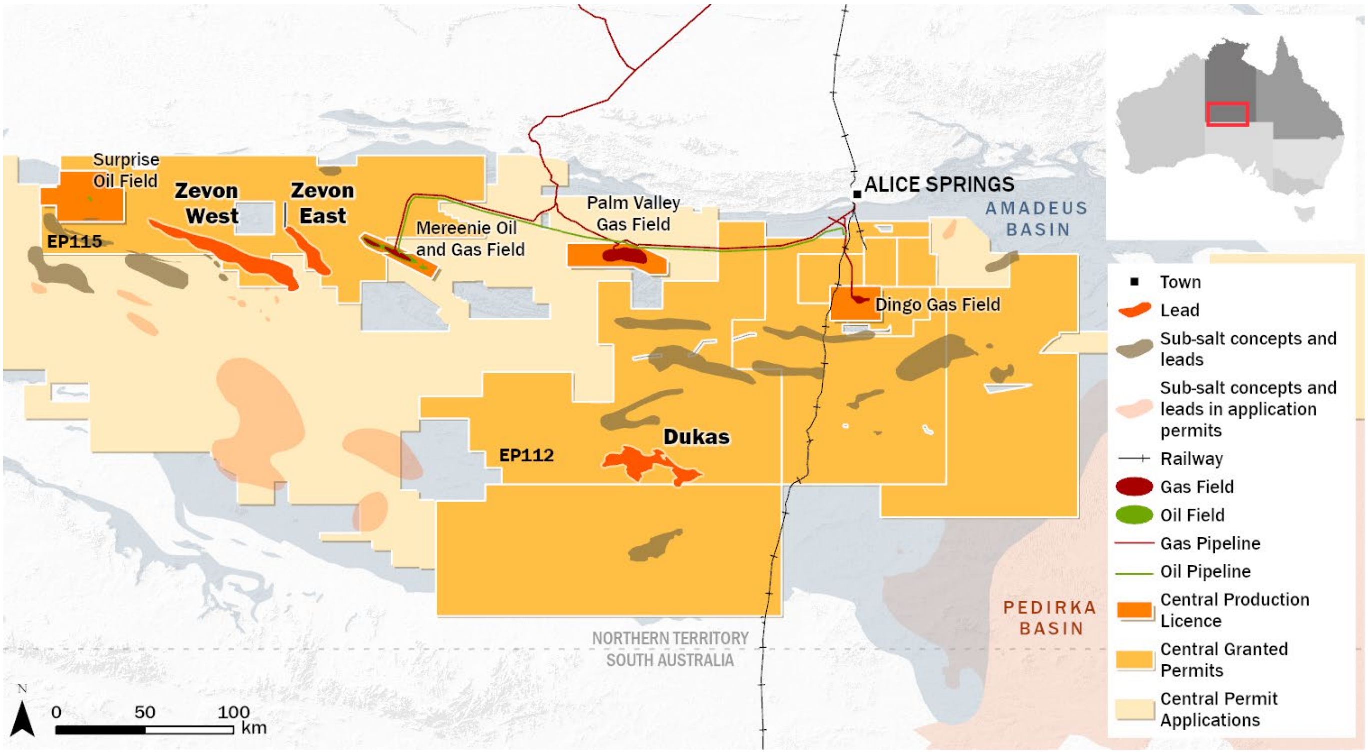
Central's interest in EP112 increased to 45% in July 2021 following an election by Santos under JV arrangements.

Zevon (EP115)

The Zevon sub-salt lead in EP115 has been defined as a potentially very large closure (circa 1,600 km^2) from seismic and gravity studies. It is located in the north-western section of the Amadeus Basin between the Mereenie oil & gas field and the Surprise oil field.

The Zevon area is interpreted as a regional-scale basement high, sub-divided into two leads, Zevon East (180km^2) and Zevon West (582 km^2). Regional geological play mapping has highlighted that this area has the potential to be highly prospective for Helium and Hydrogen in association with hydrocarbon gasses.

A 30km experimental seismic line will be acquired in late 2021 to optimise the acquisition parameters for a subsequent larger seismic program. Work has commenced on planning the larger, circa 700km, 2D seismic survey ahead of identifying a drilling location in the Zevon area.



Location of Dukas and Zevon sub-salt targets

Southern Amadeus Basin, Northern Territory

Various Exploration Permits (see table on page 107)

In addition to the large sub-salt leads, such as Dukas, secondary reservoir objectives are present within the post-salt units including the Areyonga Formation and Pioneer Sandstone, both of which are gas bearing at the Ooraminna discovery. The Dingo Deep exploration well will provide important data on these deeper targets in early 2022, which will feed into the planning for future activities at Ooraminna.

Central continues to mature its geological interpretations in these permits, seeking to identify a variety of other exploration play types and targets which could be prospective for hydrocarbons and/or Helium.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 107)

The Company continued to evaluate a number of these areas and has been working to gain Native Title/Aboriginal Land Rights Act clearance and secure the other necessary approvals in advance of the award of exploration permit status.

Play types and leads are also being developed for the under-explored sedimentary section underlying the proven Ordovician Larapintine system. This deeper section is believed to be prospective for gas.

In the Wiso Basin, a gravity survey was conducted by Geoscience Australia and the Northern Territory Geologic Survey in 2013, which has provided Central with improved detail of structural trends. Interpretation and forward modelling in conjunction with magnetic, borehole and outcrop data has led to the generation of a depth to basement map. This will help with the planning of a proposed seismic acquisition program which will form part of the first phase of exploration once tenure is granted.

OPERATING AND FINANCIAL REVIEW

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(CTP—100% interest)

Geology and geophysical studies continued, focussing on the Ethabuka structure.

Helium and Hydrogen potential of the Amadeus Basin

Helium is the second lightest and second most abundant element in the Universe. It is used as a cooling agent for MRI's, super conducting magnets, satellite instrumentation, leak detection, car airbags, welding Aluminium, and mixed with Oxygen for deep sea diving.

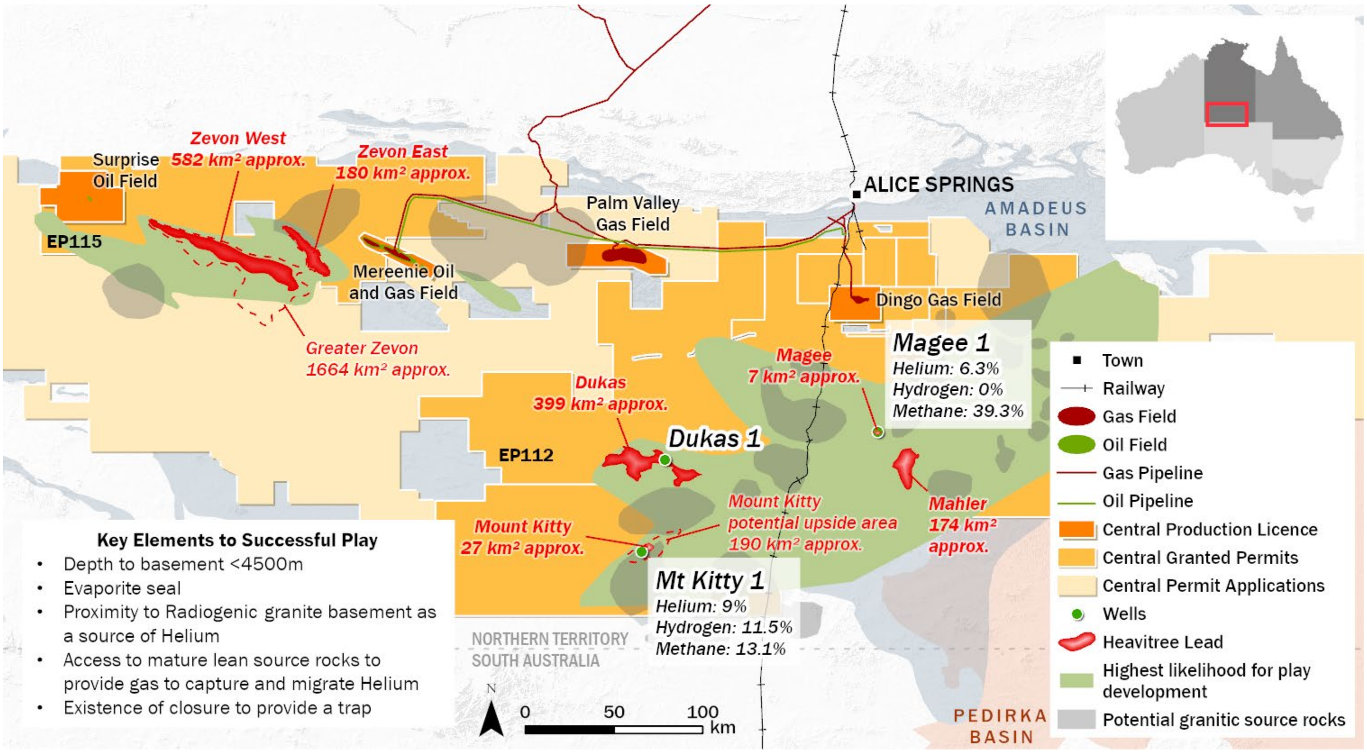
Helium is exceptionally rare on Earth as the Earth's crust is only about 8 parts per billion Helium. Currently, all Helium production is derived as a by-product of hydrocarbon bearing gas accumulations. In 2019, there were only 16 Helium plants wordwide which refine Helium into a liquid form. The US was the largest producer (53% share worldwide) and had the largest Helium reserves. The price of bulk liquid Helium has increased by 250% in the last decade.

In Australia, the only commercial quantities of Helium are extracted from the tail of LNG production at the Darwin LNG plant, which is fed by gas from the Bayu-Undan field in the Timor Sea. Helium is present in concentrations of 0.1% in the raw gas and becomes enriched in the tail gas of the LNG process to 3% whereupon it is utilised as feedstock for Helium extraction.

The Amadeus Basin is highly prospective for Helium and Hydrogen due to a combination of a radiogenic granitic source in the basement and the presence of thick evaporitic seals which immediately overlies the fractured basement and the Heavitree Formation, both of which act as potential reservoirs.

Evidence of a working system for Helium and Hydrogen is provided by gas compositions from the Mt. Kitty-1 and Magee-1 wells, which recorded 9% and 6% Helium respectively in combination with hydrocarbon gasses and Nitrogen on well test. In addition, 11% Hydrogen was recorded in Mt. Kitty-1. Helium concentrations above 1% are regarded globally as high, with a concentration of greater than 0.5% regarded as potentially economic.

A Helium play map for the Amadeus Basin has been constructed in-house by identifying areas which contain the critical geological elements required to make a potential Helium discovery (below).



Amadeus Basin Helium play map

COMMERCIAL

Sell-down of Amadeus Production Assets

On 25 May, Central announced it had entered into a binding agreement to sell 50% of its current working interest in its Amadeus Basin Production Assets to entities controlled by New Zealand Oil and Gas Limited ("NZOG") and Cue Energy Resources Limited ("Cue") (the "NZOG Entities") for total consideration valued at circa $85 million (the "Transaction").

The assets being sold under the Transaction consist of 50% of Central's interests in its producing assets in the Northern Territory, namely, the Mereenie Oil and Gas Field (OL 4/5) ("Mereenie"); Palm Valley Gas Field (OL3) ("Palm Valley"); and Dingo Gas Field (L7) ("Dingo") (together, the "Production Assets").

The Transaction comprises a sale of a 50% interest in Central's share of the Production Assets, with an effective date of 1 July 2020 in return for consideration comprising of:

- an upfront cash payment of $29 million;
- $40 million payment by way of "carried" funding for Central's share of near-term development, appraisal and exploration activities;
- $23 million (Central's book value at the effective date) through an assumption by the NZOG Entities of obligations to supply up to 4.9 PJ of gas (50% interest acquired at the effective date) which has previously been paid for but not delivered under pre-sale or 'take-or-pay' arrangements; and
- a completion adjustment for net cash flows generated between the effective date and the completion date.

The Transaction "carry" of $40 million net to Central covers payment of certain of Central's JV expenditure obligations for near-term development and growth activities across the Production Assets with a total gross JV cost of over $100 million. This includes two committed exploration wells to commence later this year (Palm Valley Deep and Dingo Deep, with options to complete these wells as producers from the existing production intervals) as well as two production wells at Mereenie which will be commissioned in the first quarter of FY2022.

Central will repay circa $30 million of the Macquarie Bank loan facility at completion.

The Transaction is expected to complete on 1 October 2021 and result in an after-tax accounting profit net to Central of circa $35 million on the sale[1].

Transaction meets strategic objectives and opens multiple avenues for growth

Value accretive	$85m consideration[(1)] for 50%, with an expected circa $35m profit[(1)], delivers a strong signal for the underlying value and quality of Central's Amadeus Basin Producing Assets
Accelerates Growth	Provides $40m free-carry for near term exploration and development, which would facilitate approximately $100m (gross JV) investment across the Sale Assets without any further cash outlay from Central
Diversifies risk	Accelerates growth in the Amadeus Basin while sharing and diversifying geological, exploration and development risk through a new joint venture
Aligned partner	Introduces technically capable partner(s) with financial capacity and aligned objectives
Operatorship	Central retains operatorship
Balance Sheet	Strengthens Central's balance sheet through reduction of debt (by $30m) and deferred gas liabilities (by $21m)[(2)]

1 Estimated value if the transaction completed on 1 August 2021 and subject to final determination of the completion adjustment and movements in liabilities associated with the Sale Assets between the effective date and the actual completion date.

2 Based on Central's book value for these liabilities at the effective date, including pre-sale subsequently executed in December 2020.

Central retains its existing interests in significant growth opportunities not included in the Transaction, including: the Range Coal Seam Gas Project (50%); EP82 Dingo Satellite Area ("DSA") including the Orange-3 target (100%); Mamlambo oil target close to the Surprise oil field in L6 (100%); EP115 including the Zevon multi-Tcf sub-salt target (100%); and EP112 including the Dukas multi-Tcf sub-salt target (45%).

Amadeus to Moomba Gas Pipeline (AMGP)

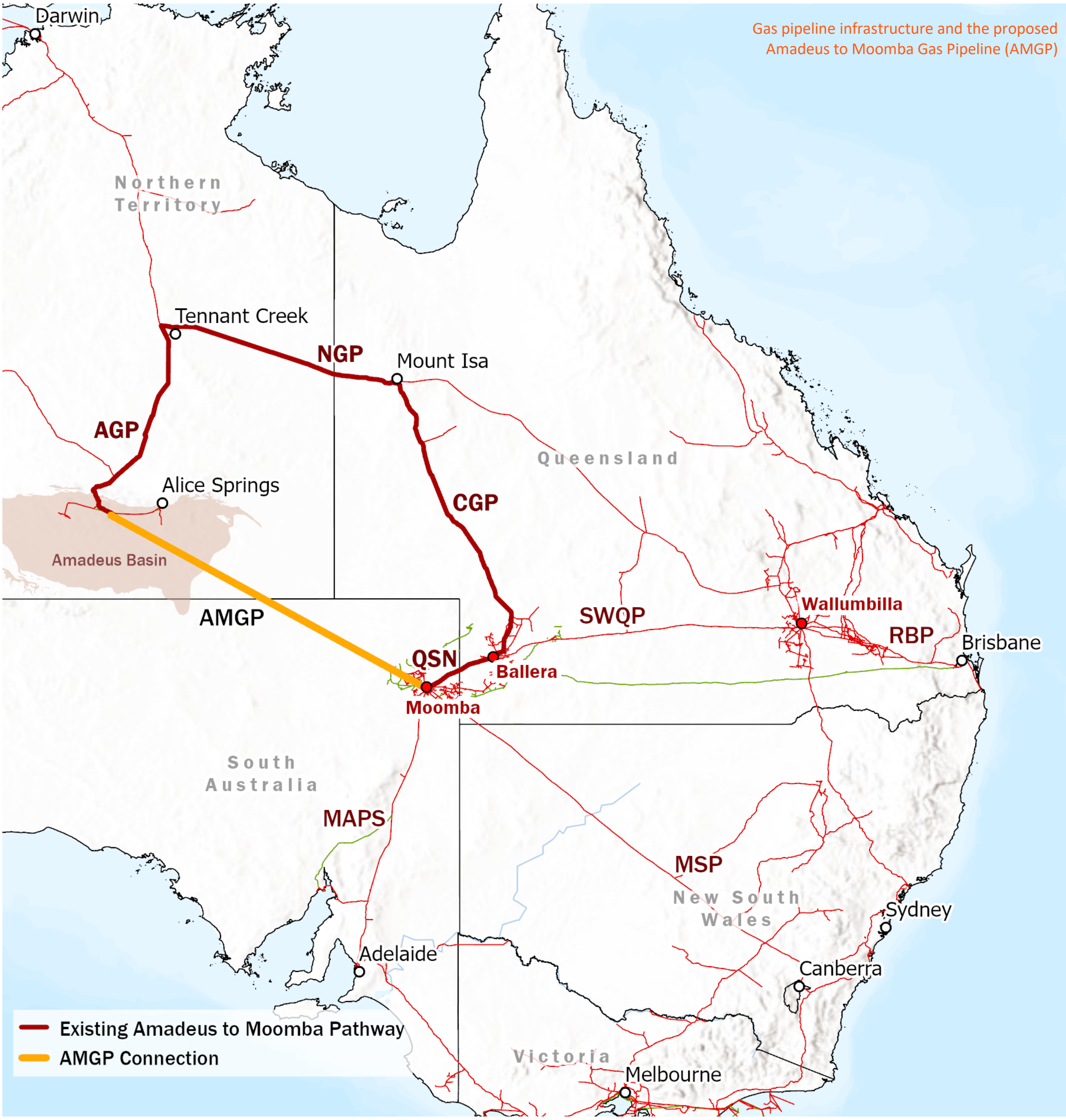
In August 2020, Central (as a potential foundation customer) executed a Memorandum of Understanding with its Mereenie JV partner, Macquarie Mereenie Pty Ltd and Australian Gas Infrastructure Group (AGIG) to progress towards FID for the development of a new 950km gas pipeline from the Amadeus Basin to the Moomba gas hub.

The proposed Amadeus to Moomba Gas Pipeline (AMGP) would cut 1,250 km from the current route to Moomba, offering more cost-efficient access to the deeper, higher-priced gas markets of south-eastern Australia.

The AMGP project is already well defined, having previously completed front-end engineering and design as the subject of a firm offer by AGIG under the North East Gas Interconnect selection process conducted in 2015.

Central's operated fields in the Amadeus Basin have approximately 200 PJ of uncontracted conventional gas reserves (gross JV) which can be supplied to market through the AMGP. Further foundation supplies from Central's operated gas fields will be required for FID.

Two exploration wells, set to start drilling in late 2021, are targeting an additional 192 PJ of mean prospective gas resources (gross JV). Gas discoveries resulting from this exploration program or Central's future NT exploration activity in the underexplored, but highly prospective Amadeus Basin (including Orange, Zevon and Dukas), could be a catalyst for the development the AMGP.



RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 151.7 PJE at 30 June 2021.

Upon completion of the partial asset sale announced on 25 May 2021, Central's interest in the reserves and resources set out below at Mereenie, Palm Valley and Dingo will be reduced by approximately 50%.

Aggregate Reserves and Resources

		As at 30/06/2020	1 July 2020 – 30 June 2021 Production	As at 30/06/2021	Comprising[1] Developed	Undeveloped
Oil						
Proved reserves (1P)	mmbbl	0.77	(0.08)	**0.69**	0.47	0.22
Proved plus probable reserves (2P)	mmbbl	0.97	(0.08)	**0.89**	0.75	0.14
Contingent Resources (2C)	mmbbl	0.10	—	**0.10**	—	—
Gas						
Proved reserves (1P)	PJ	123.24	(9.07)	**114.18**	81.22	32.96
Proved plus probable reserves (2P)	PJ	155.56	(9.07)	**146.50**	115.58	30.92
Contingent Resources (2C)	PJ	239.88	—	**239.88**	—	—

[1] All developed and undeveloped 1P and 2P reserves are located in the Amadeus Basin geographical area.

Reserves and Resources by Field

		As at 30/06/2020	1 July 2020 – 30 June 2021 Production	As at 30/06/2021
Mereenie, oil				
Proved reserves (1P)	mmbbl	0.77	(0.08)	**0.69**
Proved plus probable reserves (2P)	mmbbl	0.97	(0.08)	**0.89**
Contingent Resources (2C)	mmbbl	0.10	—	**0.10**
Mereenie, gas				
Proved reserves (1P)	PJ	69.26	(4.61)	**64.65**
Proved plus probable reserves (2P)	PJ	91.82	(4.61)	**87.22**
Contingent Resources (2C)	PJ	91.20	—	**91.20**
Palm Valley				
Proved reserves (1P)	PJ	24.73	(3.24)	**21.49**
Proved plus probable reserves (2P)	PJ	27.66	(3.24)	**24.42**
Contingent Resources (2C)	PJ	13.68	—	**13.68**
Dingo				
Proved reserves (1P)	PJ	29.26	(1.22)	**28.04**
Proved plus probable reserves (2P)	PJ	36.08	(1.22)	**34.86**
Range (Surat Basin, Qld)				
Contingent Resources (2C)	PJ	135.00	—	**135.00**

Note: Estimates may not arithmetically balance due to rounding.

Qualified Petroleum Reserves and Resources Evaluator Statement

The information contained in this Reserves and Resources Statement is based on, and fairly represents, information and supporting documentation reviewed by Mr Kevan Quammie who is a full-time employee of Central Petroleum holding the position of Development & Appraisal Manager. Mr Quammie holds an M.Sc. Petroleum and Natural Gas Engineering from the Pennsylvania State University, is a member in good standing of the Society of Petroleum Engineers, is qualified in accordance with ASX listing rule 5.41. and has consented to the inclusion of this information in the form and context in which it appears.

The reserves and resources information in this document relating to:

- the Mereenie, Palm Valley and Dingo fields are based on, and fairly represent information and supporting documentation reviewed by Mr Kevan Quammie who is a full-time employee of Central Petroleum Limited holding the position of Development and Appraisal Manager and is a member in good standing of the Society of Petroleum Engineers; and
- the Range Gas Project resources were first reported to the market on 20 August 2019 and are based on, and fairly represent information and supporting documentation reviewed by Mr John Hattner who is a full-time employee of Netherland, Sewell & Associates, Inc., holding the position of Senior Vice President and is a member in good standing of the Society of Petroleum Engineers.

Central Petroleum Limited is not aware of any new information or data that materially affects the information included in this document and all the material assumptions and technical parameters underpinning the estimates in the relevant market announcement continue to apply and have not materially changed.

Reserves and resources estimates are prepared by suitably qualified personnel in a manner consistent with the Petroleum Resources Management System (PRMS) 2018 published by the Society of Petroleum Engineers (SPE). Reserves and resources estimates are reviewed at least annually or when new technical or commercial information becomes available. Additionally, external certification is conducted periodically.

RISK MANAGEMENT

Central Petroleum recognises that risk is inherent in our business and the effective management of risk is vital to deliver our strategic objectives, continued growth and success. We are committed to managing risks in a proactive, robust, and effective manner, to help achieve our objectives.

Our risk management process is designed to recognise and manage risks that have the potential to materially impact on Central's business objectives. This process is aligned to the international standard ISO31000 for risk management and assesses potential risks across our business and considers impacts on the health and safety of our employees, the environment and communities in which we operate, our financial stability, our reputation and legal and compliance obligations.

Climate change and the transition to a lower-carbon economy influences Central Petroleum's strategy, presenting both risk and opportunity in the operation of our existing assets and commercialisation of our growth portfolio. We aim to leverage our risk management framework to ensure an integrated and coordinated approach to the management of climate change across the business.

Principal risks and uncertainties at 30 June 2021

The principal risks and uncertainties outlined in this section may materialise independently, concurrently or in combination and may impact Central's ability to meet its strategic objectives.

Context	Risk	Mitigation
Social and Legal License to Operate		
Our business performance is underpinned by our social license to operate, that requires compliance with legislation and the maintenance of a high standard of ethical behaviour and social responsibility. Our business activities are subject to extensive regulation and government policy. Failure to comply may impact our license to operate. Stakeholders have evolving expectations of social responsibility and ethical decision making. These are changing at a rate faster than governments can introduce or amend regulation.	Failure to meet stakeholder expectations can lead to opposition and a decline in support for both our operational activities and future growth opportunities. A significant or continuous departure from national or local laws, regulations or approvals, or the introduction of new laws and regulations may result in negative social, cultural and reputational impacts, loss of license to operate and could impact our ability to operate or pursue our growth strategy. Violation of anti-bribery and corruption laws may expose Central to fines, sanctions, and civil suits, and negatively impact our reputation.	Central proactively maintains and builds our social license to operate through the application of our values, effective stakeholder engagement strategies, and our regulatory compliance framework. We have a robust framework in place to support our regulatory and compliance obligations and we continue to strengthen our regulatory compliance framework and supporting tools. We proactively maintain open dialogue with governments, regulators, and stakeholders within jurisdictions in which we operate. Our fraud and corruption framework aims to prevent, detect, and respond to unethical behaviour. It incorporates policies, procedures, and training to ensure activities are conducted ethically.

Context	Risk	Mitigation
Growth		
Our future growth depends on our ability to identify, acquire, explore, appraise, and develop resources.	The inability to identify and commercialise growth opportunities, or realise their full value, may result in a loss of shareholder value. Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy.	We engage experienced, skilled personnel to identify and progress a suite of commercially attractive and sustainable opportunities that complement our existing assets, enable portfolio diversity and optimise our commercial position. Exposure to reserve depletion is addressed through our exploration strategy. We continue to analyse existing acreage for exploration drilling prospects.
Our ability to successfully deliver value adding projects is also critical.	Central is exposed to market and industry conditions - some beyond our control, which may impact project delivery and lead to cost overruns or schedule delays when developing and executing our portfolio of capital projects.	We utilize an established project management framework which is supported by skilled and experienced personnel to govern and deliver major projects.
Oil and Gas Reserves		
Commercialisation of hydrocarbons reserves is a key contributor to our long-term success.	Uncertainty in hydrocarbon reserve estimation and the broad range of possible recovery scenarios from existing resources could have a material adverse effect on our operations and financial performance.	Our reserve and resource estimates are prepared in accordance with the guidelines set forth in the 2018 Petroleum Resources Management System (PRMS). We proactively analyse reservoir performance and undertake comprehensive production and economic modelling to determine the most likely outcomes across our fields.
Climate Change		
Climate change is impacting the way that the world produces and consumes energy.	Demand for oil and gas may subside over the longer-term, impacting demand and pricing as lower carbon substitutes take market share. Global climate change policy remains uncertain and has the potential to constrain Central's ability to create and deliver stakeholder value from the commercialisation of hydrocarbons. Introduction of taxes or other charges associated with carbon emissions may have an adverse impact on Central's operations, financial performance and asset values.	We are focused on ensuring our portfolio is robust in a potentially carbon constrained market and engage proactively with key industry and government stakeholders. Our development is predominantly focused on gas as a transition fuel which could see demand for natural gas increase in the medium term as part of a transition to a clean energy future compared to other hydrocarbon energy sources. Central also seeks value accretive opportunities to reduce carbon emissions and/or utilize or sequester carbon, with both Palm Valley and Mereenie potential candidates for carbon capture and storage (CCS). Central has opportunities to diversify its reliance on hydrocarbon by targeting valuable non-hydrocarbon gases such as Helium and naturally occurring Hydrogen which have been measured in some of its exploration tenements.
Community		
Our proactive engagement and support of local and indigenous communities is at the core of how we operate.	Our interactions with, and decisions involving landholders, traditional owners, suppliers and the community fails to attract and maintain the continued support of the communities in which we operate.	We work in conjunction with our key stakeholders and have established programs to support and assist the communities in which we operate through donations, sponsorships, local procurement, training and providing ongoing local employment and business opportunities.

Context	Risk	Mitigation
Health and Safety		
Health and Safety is at the heart of all activities and decisions at Central.	Health and Safety incidents or accidents may adversely impact our people, the communities in which we operate, our reputation and/or our licence to operate.	Health and Safety is an area of focus for Central and our risk management framework includes auditing and verification processes for our critical controls. We also regularly review our operations and activities to ensure we operate with the required standards of safety management.
	Potential exposure of employees and contractors to COVID-19 and the potential transmission to communities in which we operate.	All operational activities including travel to and from sites are managed under a Pandemic (COVID-19) Management Plan. Although we continue our support, we are limiting company-initiated face to face engagement with traditional owner communities. We continue to monitor and align our standards and approach with guidance from various government and health authorities.
Operating		
The production and delivery of hydrocarbon products safely and reliably are key elements of our operational and financial performance and directly impact shareholder returns.	Reservoir / field performance is subject to subsurface uncertainty. The actual performance could vary from that forecasted, which may result in diminished production and /or additional development costs. Our facilities are subject to hazards associated with the production of gas and petroleum, including major accident events such as spills and leaks which can result in a loss of hydrocarbon containment, diminished production, additional costs, environmental damage or harm to our people, reputation or brand.	We continually monitor field performance and schedule production optimisation and development activities to extract maximum value from the field and to mitigate any potential reservoir under-performance. Our operational performance is based on a framework of controls which enable the management of these risks. We have in place asset integrity management processes, inspections, maintenance procedures and performance standards across all infrastructure to maximise reliable and safe operations. Central maintains insurance in line with industry practice and sufficient to cover normal operational risks. However, Central is not insured against all potential risks because not all risks can be insured cost effectively. Insurance coverage is determined by the availability of commercial options and cost/benefit analysis, considering Central's risk management program.
	In addition, our operations can be negatively impacted by employee and contractor availability due to the impacts associated with COVID-19 including shutting down for a period.	All operational employee and contractor activities are managed under a Pandemic (COVID-19) Management Plan to minimise the risk of impacts to operations.
People and Culture		
We must have the right capability and capacity within our business through personnel who are engaged and enabled to deliver our current business and future growth opportunities.	Failure to establish and develop sufficient capability and capacity to support our operations may impact achievement of our objectives.	Central's focus remains on securing and developing the right people to support the development of our portfolio of assets and opportunities. Our focus remains on creating a positive employer value proposition, planning our resource requirements and attracting talented individuals. We also proactively engage contractors to supplement any short-term gaps in capability and capacity to support the execution of our business plans.

Context	Risk	Mitigation
Financial		
Our financial strength and performance underpins our strategy and future growth.	Insufficient liquidity to meet financial commitments and fund growth opportunities could have a material adverse effect on our operations and financial performance.	We have a robust expenditure management and forecasting process which is monitored against a Board approved budget to ensure capital is allocated in accordance with the company's strategy. We actively manage debt and other funding sources to ensure the business is appropriately capitalized to sustain ongoing operations and growth plans. We also actively seek partnering opportunities to share risks and assist in funding key activities on a project-by-project basis.
Our revenue is from the sale of hydrocarbons. This underpins Central's financial performance.	Central is exposed to USD commodity price variability with respect to crude oil sales which are impacted by broader economic factors beyond our control. Central is exposed to gas commodity prices with respect to gas sales, all of which are to the Northern Territory and Australian east coast markets. In addition to normal demand and supply forces, gas prices in these markets are subject to risk of Government intervention in the form of the Australian Domestic Gas Supply Mechanism; although this mechanism is focused on availability of supply and is not considered to have significant potential impact on price.	Oil revenue represented less than 10% of consolidated sales revenue in FY2021. The majority of Central's revenue is from natural gas sales denominated in AUD and the short-term uncertainty with this commodity is largely mitigated through medium and long term fixed-price gas sales agreements with 'take-or-pay' provisions.
Environment		
Our environmental performance underpins our licence to operate.	Our operations by their nature have the potential to impact air quality, biodiversity, land and water resources and related ecosystems. A failure to manage these could adversely impact not just the environment, but our people, the communities in which we operate, our reputation and our licence to operate.	Environmental management is a very high priority for Central. We operate under approved Field Environmental Management Plans and have a program of regular environmental inspections and audits in place to ensure compliance. We also continue to assess and develop our standards to prevent, monitor and limit the impact of our operations on the environment. We carry third party environmental liability insurance in addition to well control insurance to mitigate financial impacts should an event occur.
Digital and Cyber Security		
We are reliant upon our systems and infrastructure availability and reliability to support the business operating safely and effectively. Cyber risks continue to evolve with greater levels of sophistication.	Failure to safeguard the confidentiality, integrity, availability and reliability of digital data and intellectual property. Central's information and operational technology systems may be subject to intentional or unintentional disruption (e.g. cyber security attack) which could impact our ability to reliably supply customers.	Digital risks are identified, assessed and managed based on the business criticality of our systems, which may be segregated and isolated if required. We continuously assess and determine access permissions to critical information or data, whilst consolidating, simplifying, and automating security controls. Our exposure to cyber risk is managed by a proactive and continuing focus on system controls such as firewalls, restricted points of entry, multiple data back-ups and security monitoring software. We are continuing to embed a cyber-safe culture across Central.

Context	Risk	Mitigation
Geographic Concentration		
We face risks associated with the concentration of our production assets.	Central's revenue is derived from oil and gas production in the Amadeus Basin leaving Central exposed to downsides associated with weather conditions and infrastructure failure.	We ensure that appropriate insurance is in place to mitigate the impact of any extended business interruption. The new Range coal seam gas project in the Surat Basin is increasing the geographical diversification of our business. We are also investigating other new ventures outside of the Amadeus Basin.
Access to Infrastructure		
Our financial performance and growth strategy are dependent on access to third party owned infrastructure.	Negative impacts to revenue as a result of infrastructure failure, increased tariffs, or restricted access to third party owned infrastructure.	We seek to work closely with customers and suppliers of infrastructure to mitigate the risk of delays or failure. We continue to explore alternative routes to market to diversify risk where possible.
Joint Ventures		
Although we operate most of the tenements we hold, we are dependent on technical and commercial alignment with our joint venture partners.	Misalignment between joint venture partners can lead to scarcity of available capital and may impact the prioritisation of exploration, development or production opportunities. This can lead to delayed approvals which may impact Central's growth strategy.	We work closely with our joint venture partners to achieve mutually beneficial outcomes.

SUSTAINABILITY AND COMMUNITY

Central Petroleum takes its responsibilities to the environment, landowners and cultural heritage very seriously – we operate in some of Australia's most stunning and pristine environments, rich in indigenous culture with diverse flora and fauna.

As custodians of the land on which we operate, we aim to uphold the highest environmental standards and leave the smallest footprint, so that when we finish extracting unseen resources from far beneath the surface, the land will be just as we found it, for future generations to enjoy.

Environmental

Our operations are conducted under comprehensive government-approved Environmental Management Plans (EMPs) in compliance with all relevant Commonwealth and State legislation. The EMPs typically set out detailed requirements for all aspects of environmental protection, including levels for waste and water management, air emissions, land disturbance and rehabilitation, soil and flora/fauna conservation including pest and weed control as well as bushfire prevention.

We have had several visits and inspections during the year by multiple regulatory agencies to monitor environmental conditions associated with our operations and drilling programs. These visits and inspections complement our own internal monitoring and assurance programs. Audit of compliance with our environmental conditions outlined in the various EMPs over the course of the year identified over 95% compliance with no non-compliances noted. There were no reportable environmental incidents during the year.

No fracture stimulation (fracking) activities are conducted in our production or exploration areas.

Climate change and emissions

Central recognises that climate change is an increasingly significant environmental, social, and business issue. We believe that natural gas plays a pivotal role in providing cleaner, affordable, and reliable energy under a coordinated approach with our governments and communities as we transition to a lower-emission energy future.

The regulatory, scientific, and social response to climate change continues to evolve and, in this context, we continue to seek ways to minimise our carbon emissions while also providing affordable, reliable energy to our customers.

We report our greenhouse emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER). In the most recent completed reporting period, FY2020, our share of scope 1 and 2 emissions across our operations was 47,545 tons of CO_2e. We are working on several initiatives to reduce our emissions, including a flare gas recovery project at Mereenie, which will seek to reduce flare gas emissions by more than 25% and overall emissions at these sites by approximately 10%, based on current emissions. As older legacy equipment is replaced, we are installing more efficient appliances which will further reduce Scope 1 emissions across our operations.

Central is also investigating the possibility of using the depleted reservoirs in its long-producing Amadeus Basin fields for carbon capture and storage (CCS) in conjunction with potential CCS projects in the area.

Zebra finches near WM27 drilling site
Photo by Phil Allen

Community

Central works closely with the communities in which it operates. We rely on the support of our local communities, landowners, and other stakeholders, and in return we seek to provide employment and business opportunities to our local communities.

In the Northern Territory, for example:

- 59% of our staff live locally
- 30% of our staff are indigenous
- We paid over $4.0M of Royalties to the Northern Territory and Central Land Council in FY2021.

We aim to pay all of our suppliers on time in accordance with the agreed terms, which usually would not exceed 30 days after the end of the month of invoicing.

Many of Central's operations in the NT are located on or near Indigenous lands and we recognise, embrace, and respect the Indigenous historical, legal and heritage ties to these lands. We are committed to engage openly with the Traditional Owners and provide employment and training opportunities to the Indigenous people. We work closely with the Central Land Council and Aboriginal Areas Protection Authority to ensure our operations do not disturb areas of cultural heritage significance.

Other high-value, non-hydrocarbon gases

Central's Amadeus Basin tenements are also prospective for other high-value, non-hydrocarbon gases such as Helium and Hydrogen. Radiogenic basement rocks and an evaporitic sealing unit have created the ideal conditions for a Helium and Hydrogen play in the sub-salt section of the Amadeus Basin.

The Mt Kitty-1 well recorded gas composition including 9% Helium and 11% Hydrogen. Helium has also been measured at the Magee-1 and Dukas-1 wells.

Central views the opportunity to discover and commercially produce these high-value non-hydrocarbon gasses as a growing and important aspect of our exploration and business development strategies.

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2021

Your Directors present their report on the consolidated entity, consisting of Central Petroleum Limited ("the Company", "Central" or "CTP") and the entities it controlled (collectively "the Group" or "the Consolidated Entity") at the end of, or during, the year ended 30 June 2021.

DIRECTORS

The names of the Directors of the Company in office during the financial year and until the date of this report are set out below. Directors were in office for this entire period unless otherwise stated.

Current Directors:

Mr Michael (Mick) McCormack (Chair, appointed as Director on 1 September 2020)

Mr Leon Devaney (Managing Director)

Mr Stuart Baker

Mr Stephen Gardiner (appointed 1 July 2021)

Ms Katherine Hirschfeld AM

Dr Agu Kantsler

Former Directors:

Dr Julian Fowles (resigned 31 October 2020)

Mr Wrixon Gasteen (resigned 28 November 2020)

PRINCIPAL ACTIVITIES

The principal activities of the Consolidated Entity constituting Central Petroleum Limited and the entities it controls consists of development, production, processing and marketing of hydrocarbons and associated exploration.

DIVIDENDS

No dividends were paid or declared during the financial year (2020: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- Strong annual sales volumes and revenues:
  - Volumes 10.3 PJe
  - Revenues $59.8 million.
- EBITDAX of $26.1 million.
- Full year profit of $0.3 million.
- Reduced net debt by 32% to $31.3 million and extended loan facility by 12 months to late 2022.
- Announcement of a binding agreement to sell down 50% of working interests in Amadeus Basin Producing Assets to help accelerate exploration, appraisal and development activity across the fields. Central to retain Operatorship of all fields.
- Successfully drilled a three well pilot program at the Range CSG Project and commenced testing.
- Recompleted four wells and commenced drilling the first of two new production wells at the Mereenie field.
- Announced an MOU with Australian Gas Infrastructure Group (AGIG), to participate as a foundation customer to progress towards a final investment decision on a proposed major new pipeline that would enable Central's gas to be transported direct to the Moomba gas supply hub and the larger south-eastern Australian gas markets with significantly greater cost efficiencies.
- Strengthened the Board with the appointment of Mr Mick McCormack as Chair and Mr Stephen Gardiner as a Director, both highly respected industry leaders with extensive experience in the energy sector.

A detailed review of the operating and financial performance for the year ended 30 June 2021, including principal risks is provided from pages 3 to 27 of this Annual Report.

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

The financial position and performance of the Group was particularly affected by the following events and transactions during the year ended 30 June 2021:

- Strengthening oil & gas markets and implementation of cost control initiatives resulted in a 4% increase in underlying EBITDAX from the previous year.
- Announcement of a binding agreement to sell down 50% of working interests in Amadeus Basin Producing Assets to help accelerate exploration, appraisal and development activity across the fields. Central to retain Operatorship of all fields.
- Successfully drilled a three well pilot program at the Range CSG Project and commenced testing.
- Recompleted four wells and commenced drilling the first of two new production wells at the Mereenie field.
- Pre-sold 3.5 PJ of gas for delivery in 2022/2023.
- Announced an MOU with Australian Gas Infrastructure Group (AGIG), to participate as a foundation customer to progress towards a final investment decision on a proposed major new pipeline that would enable Central's gas to be transported direct to the Moomba gas supply hub and the larger south-eastern Australian gas markets with significantly greater cost efficiencies.

There were no other significant events that are not detailed elsewhere in this Annual Report.

EVENTS SINCE THE END OF THE FINANCIAL YEAR

Increased interest in EP112

Effective 31 July 2021, Central's interest in EP112 increased from 30% to 45% as a result of joint venturer, Santos, not electing that Central be carried for the first $3,000,000 of future Dukas well costs.

Asset Sale

On 17 September 2021 the agreement for the sale of 50% of the Group's producing assets to New Zealand Oil & Gas Limited and Cue Energy Resources Limited became unconditional and the transaction is expected to complete on 1 October 2021.

No other matter or circumstance has arisen between 30 June 2021 and the date of this report that will affect the Group's operations, result or state of affairs, or may do so in future years.

LIKELY DEVELOPMENTS AND EXPECTED RESULTS OF OPERATIONS

The partial sell-down of Central's producing assets is expected to complete on 1 October 2021 and provide Central with the opportunity to accelerate its growth plans for the broader Amadeus Basin. The transaction will stimulate over $100 million of gross investment in Central's producing assets without further cash input from Central and allow the retirement of $30 million of debt.

Two new production wells at Mereenie will be commissioned in Q1 FY2022 and are expected to significantly boost production capacity back to over 40 TJ/d (Mereenie gross JV). While Central's share of production and reserves will be lower following the completion of the sell-down, two new exploration wells will be drilled in FY2022 at the Palm Valley and Dingo gas fields (which are fully funded through the sale transaction) and have the potential to replace Central's divested gas reserves.

Success at Palm Valley Deep and Dingo Deep would provide a strong catalyst to open up further conventional gas plays across the basin and complement Central's efforts to support the development of a new pipeline route to gas-short southern markets via Moomba.

Central is also focussed on progressing its other larger, potentially company-changing, sub-salt targets in the Amadeus Basin which in addition to hydrocarbons, have the potential for commercial quantities of high-value Helium and Hydrogen. A return to the promising Dukas well is being planned and an initial seismic line will be shot at Zevon later this year in advance of a larger seismic acquisition program in the second half of FY2022.

The three well pilot at Central's Range CSG project in Queensland will be expanded with two new wells in late 2021, as Central advances towards a final investment decision, targeted for around March 2023.

Further information on these activities is included from pages 1 to 27 of this Annual Report.

As permitted by sections 299(3) and 299A(3) of the *Corporations Act 2001*, certain information has been omitted from the Operating and Financial Review of this report relating to the Company's business strategy, future prospects, likely developments in operations, and the expected results of those operations in future financial years on the basis that such information, if disclosed, would be likely to result in an unreasonable prejudice to Central (for example, because the information is premature, commercially sensitive, confidential or could give a commercial advantage to a third party). The omitted information relates to internal budgets, estimates and forecasts, contractual pricing, and business strategy.

INFORMATION ON DIRECTORS

Mr Michael (Mick) McCormack BSurv, GradDipEng, MBA, FAICD

Independent Non-executive Chair

Mr McCormack was appointed as a Director on 1 September 2020 and has over 37 years' experience in the energy infrastructure sector in Australia and his career has encompassed all aspects of the sector, including commercial development, design, construction, operation and management of most of Australia's natural gas pipelines and gas distribution systems. His experience extends to gas-fired and renewable power generation, gas processing, LNG and underground storage.

Mr McCormack is a former Managing Director and CEO of APA Group and former Director of Envestra (now Australian Gas Infrastructure Group), the Australian Pipeline Industry Association (now Australian Pipelines and Gas Association) and the Australian Brandenburg Orchestra. He is a director of the Clontarf Foundation and the Australian Brandenburg Orchestra Foundation and a Fellow of the Australian Institute of Company Directors.

Directorships of other listed companies in the last three years: Managing Director of APA Group (Australian Pipeline Limited) from 2006 to 2019, Director of Austal Limited from September 2020 and Director of Origin Energy Limited from December 2020.

Mr Leon Devaney BSc, MBA

Managing Director and Chief Executive Officer

Mr Devaney has over 20 years of commercial and finance experience within the Australian oil and gas sector and holds an MBA and BSc (Finance) from the University of Southern California, USA.

He joined Central Petroleum in 2012 and has been responsible for commercial, finance and business development activities in various senior roles. He was instrumental in negotiating the Mereenie acquisition from Santos in 2015 and the Palm Valley and Dingo Gas Field acquisition from Magellan Petroleum in 2014, as well as structuring the winning application for ATP2031 (Range Gas Project) in 2018. Mr Devaney was appointed Chief Executive Officer, effective February 2019, after serving as Acting CEO since July 2018.

Prior to joining Central Petroleum, he worked at QGC and played a pivotal role in its growth from a small cap gas exploration company into a multi-billion-dollar takeover target by the BG Group in 2008. He continued with BG following the QGC takeover, where he served as General Manager, Gas and Power, responsible for the domestic gas and electricity portfolio.

Prior to QGC, Mr Devaney held senior roles at Deloitte in the Corporate Finance Advisory Group where he was active in structuring and implementing commercial and financing transactions for major energy and infrastructure projects throughout Australia.

Mr Stuart Baker BE(Elec), MBA. Member, AICD

Independent Non-executive Director

Mr Baker has been a Director of Central Petroleum Limited since December 2018 and has more than four decades of experience in the oil and gas sector. He currently provides independent advice to corporates in the Australian oil and gas industry. He is a member of the Investment Committee of the ASX-listed Lowell Resources Funds Management Ltd (ASX:LRT).

Previously he was Executive Director at Morgan Stanley with dual roles of Co-Head Asia Oil, Gas and Chemicals Research and team leader for research on Australian Energy, Mining and Utility sectors, with positions held over a 13 year period.

He also held senior equity research positions in oil and gas, at Macquarie Bank and Bankers Trust in aggregate for 12 years. Prior to joining the financial services industry, Mr Baker worked at numerous oil and gas exploration and production locations throughout South-East Asia, as a senior engineer for the multi-national Houston-based oil service provider, Schlumberger Ltd.

Mr Stephen Gardiner BEc (Hons), Fellow of CPA Australia

Independent Non-executive Director

Mr Gardiner has been a director of Central Petroleum Limited since 1 July 2021. He has over forty years of corporate finance experience at major companies listed on the ASX, culminating in 17 years at Oil Search Limited including eight years as Chief Financial Officer, a role that he stepped down from in March 2021.

While at Oil Search, Stephen covered a range of executive responsibilities including corporate finance and control, treasury, tax, audit and assurance, risk management, investor relations and communications, ICT and sustainability. He also served as Group Secretary for ten years while performing his finance roles.

Prior to Oil Search, Stephen held senior corporate finance roles at major multinational companies including CSR Limited and Pioneer International Limited. Stephen has particular strength in capital management and funding, both debt and equity, having raised many billions of dollars, including via structured financings such as working on the US$15 billion PNG LNG Project financing, the largest such financing ever undertaken at the time.

Ms Katherine Hirschfeld AM BE(Chem) UQ, HonFIEAust, FTSE, FIChemE, FAICD

Independent Non-executive Director

Ms Hirschfeld was appointed as a Director in December 2018 and is a highly regarded non-executive director, having served on company boards listed on the ASX, NZX and NYSE, as well as government and private company boards. She is currently the Chair of Powerlink and a board member of Qld Urban Utilities.

Ms Hirschfeld has also been a board member and President of UN Women National Committee Australia and non-executive director of Energy Queensland, Tox Free Solutions, InterOil Corporation, Broadspectrum and Snowy Hydro. Previously she had leadership roles with BP in oil refining, logistics, exploration and production located in Australia, UK and Turkey.

Ms Hirschfeld was recognised in the AFR/Westpac 100 Women of Influence 2015, by Engineers Australia as one of Australia's Top 100 Most Influential Engineers 2015 and as an Honorary Fellow in 2014. She is a member of Chief Executive Women and a Fellow of the Australian Institute of Company Directors and the Academy of Engineering and Technology. She is also an executive mentor/coach with Merryck & Co.

In 2019 Ms Hirschfeld was appointed a Member of the Order of Australia (AM) for significant service to engineering, to women, and to business.

Directorships of other listed companies in the last three years: Tox Free Solutions Limited from 2013 to 2018.

Dr Agu Kantsler BSc (Hons), PhD, GAICD, FTSE

Independent Non-executive Director

Dr Kantsler joined the Central Board in June 2020 and is one of Australia's most respected and experienced petroleum exploration executives, having led Woodside Petroleum's world-wide exploration, business development and geotechnical activities as Executive Vice President Exploration and New Ventures from 1995 to 2009.

Prior to joining Woodside, Dr Kantsler worked for Shell in various international locations and has served as Director and Chairman of the Australian Petroleum Production & Exploration Association (APPEA). Dr Kantsler is Managing Director of Transform Exploration Pty Ltd, a Non-executive Director of Oil Search Limited since 2010 and a former President of the Chamber of Commerce and Industry WA.

Directorships of other listed companies in the last three years: Oil Search Limited from 2010.

COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

Mr White is an experienced oil and gas lawyer in corporate finance transactions, mergers and acquisitions, equity and debt capital raisings, joint venture, farmout and partnering arrangements and dispute resolution. He has previously held senior international based positions with Kuwait Energy Company and Clough Limited.

DIRECTORS' MEETINGS

The numbers of meetings of the Company's board of directors and of each board committee held during the financial year, and the numbers of meetings attended by each Director were:

	Full Meeting of Directors		Audit & Financial Risk Committee		Risk & Sustainability Committee		Remuneration & Nominations Committee	
Director	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Stuart Baker	12	12	4	4	—	4	10	10
Leon Devaney	12	12	—	4	—	4	—	8
Julian Fowles[3]	3	3	—	1	1	1	4	4
Wrixon Gasteen[4]	6	6	2	2	2	2	6	5
Katherine Hirschfeld AM	12	12	4	4	4	4	—	7
Agu Kantsler	12	12	—	4	3	4	7	8
Michael McCormack[5]	11	11	3	4	3	4	4	7

1 Number of meetings held during the time the director held office or was a member of the committee during the year.
2 The number of meetings attended includes those attended by invitation.
3 Julian Fowles resigned 31 October 2020.
4 Wrixon Gasteen resigned 28 November 2020.
5 Michael McCormack was appointed 1 September 2020.

SHARES UNDER OPTION

(a) There were no options granted during or since the end of the financial year to directors and the five most highly remunerated officers of the Company.

(b) Unissued ordinary shares of Central Petroleum Limited or interests under option at the date of this report are as follows:

Class	Issue Price	Exercise Price	Expiry Date	Number on issue
Unlisted employee options	Nil	$0.20	30 Jun 2023	18,151,116

(c) No shares were issued by Central Petroleum Limited during or since the end of the year on the exercise of options.

ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation.

The Consolidated Entity aims to ensure the appropriate standard of environmental care is achieved and, in doing so, that it is aware of and is in compliance with all environmental legislation. Audit of compliance with our environmental conditions outlined in applicable Environmental Management Plans over the course of the year identified over 95% compliance with no non-compliances noted. There were no reportable environmental incidents during the year.

INSURANCE OF DIRECTORS AND OFFICERS

During the financial year, the Group paid premiums to insure Directors and officers of the Group. The contracts include a prohibition on disclosure of the premium paid and nature of the liabilities covered under the policy.

AUDITOR'S INDEPENDENCE

A copy of the Auditor's Independence Declaration as required under section 307C of the *Corporations Act 2001* is set out on page 50.

ROUNDING OF AMOUNTS

The company is of a kind referred to in ASIC Legislative Instrument 2016/191, relating to the 'rounding off' of amounts in the directors' report. Amounts in the directors' report have been rounded off in accordance with the instrument to the nearest thousand dollars, or in certain cases, to the nearest dollar.

NON-AUDIT SERVICES

During the year the Company engaged the auditor, PricewaterhouseCoopers (PwC), on assignments additional to their statutory audit duties where the auditor's expertise and experience with the Company and/or the Consolidated Entity was important.

Details of amounts paid or payable to the auditor (PwC) for non-audit services provided during the year are set out below.

The Board of Directors is satisfied that the provision of the non-audit services is compatible with the general standard of independence for auditors imposed by the *Corporations Act 2001*. The Directors are satisfied that the provision of non-audit services by the auditor, as set out below, did not compromise the auditor independence requirements of the *Corporations Act 2001* and did not compromise the general principles relating to auditor independence in accordance with APES 110 Code of Ethics for Professional Accountants set by the Accounting Professional and Ethical Standards Board.

	Consolidated	
	2021	2020
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	9,129	14,657
Other tax related services	26,864	26,092
Total remuneration from non-audit services	**35,993**	**40,749**

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

Having successfully weathered the pandemic related market disruptions of 2020, Central emerged in FY2021 in a strong position to resume its growth-focused strategy. The sale of 50% of our operating assets to New Zealand Oil & Gas and Cue Energy Resources releases significant funding to support our growth. There has been much activity on executing our growth strategy, with pilot wells drilled at the Range Coal Seam Gas (CSG) Project, production wells drilling at Mereenie and new exploration wells at Palm Valley and Dingo set to commence drilling later this year.

Attracting and retaining key personnel to progress these activities is a key priority. Competition for experienced personnel is rising as the rebound in oil and gas markets has seen increased activity across the industry at a time when access to international workers remains restricted.

To maintain a competitive remuneration structure in these market conditions and to provide targeted performance incentives, we have made some adjustments across all the components for FY2022: fixed remuneration; short term incentives; and long term incentives, which are summarised below.

Fixed remuneration

Fixed remuneration was frozen at July 2019 levels for FY2021, consistent with the market in mid-2020, and will increase by approximately 2% in July 2021. Staff will also benefit from the 0.5% increase in compulsory superannuation contributions.

2021 STIP

The Short Term Incentive Plan (STIP) is designed to reward personnel for outcomes above expected performance. Achievement of short term incentives depends on achieving personal and corporate objectives over the year, providing an opportunity to earn up to 10% of base remuneration.

Notwithstanding difficult business conditions in CY2020 that negatively impacted production and sales, the Company was successful in achieving safety and cultural heritage KPIs, exceeded its revenue targets, successfully controlled costs and successfully drilled and commissioned the Range pilot. We also reached agreement with the NZOG group to sell 50% of our production assets, with a significant book profit expected to be realised. As a result, personnel were entitled to an average 6.7% of their maximum 10% incentive for the year.

2021 LTIP

Long term incentives are designed to align management's interests directly with those of shareholders. The Employee Rights Plan / Long Term Incentive Plan (LTIP) targets half of its reward outcomes to Central's shares outperforming those of its peer group (Relative Total Shareholder Returns) and half to Absolute Total Shareholder Returns (TSR). Absolute TSR must exceed 10% per annum for three years to achieve any part of this second element and 25% per annum for three years to receive the whole of this element.

The LTIP's Absolute TSR performance for the three years from 1 July 2018 to 30 June 2021 failed to achieve the minimum growth hurdle of 10% pa. Whilst disappointing, Central's share price performance over this period was not inconsistent with that of its peers and the Relative TSR placed Central above the 50th percentile compared to its peers, resulting in 31.5% of rights vesting for this three year performance period. As included in the LTIP plan rules, the Board has discretion to retest performance of these hurdles at 31 December 2021.

With increasingly competitive labour markets, the Board has undertaken an external review of our incentive schemes with the aim of ensuring alignment with our short-term priorities and longer-term strategies.

We are cognizant that the success of our transformational growth programs in the next couple of years, both in the Amadeus and at the Range CSG Project, are critical to delivering shareholder value. As a result, we are re-weighting our incentive schemes to deliver more reward for near-term performance.

For FY2022 our executive team will participate in an incentive program that integrates short and long-term components. Performance against our KPI targets in FY2022 will determine the size of the earned reward, with most of the value converting into share rights vesting over the following three years.

Other key members of staff will share in a broader short-term cash incentive plan targeting near-term performance in lieu of future participation in the equity-based LTIP of previous years.

Consistent with previous years, we have included a Realised Remuneration table (refer Table 1 in section I of the Remuneration Report) to assist readers of this report to understand the actual remuneration which the senior executives have received this year – something which is not always clear with the statutory reporting requirements.

We are confident the remuneration decisions taken this year will meet the expectations of our shareholders and look forward to sharing the success as we pursue our growth plans.

Michael (Mick) McCormack
Remuneration and Nominations Committee Chair

REMUNERATION REPORT
(AUDITED)

This Remuneration Report for the year ended 30 June 2021 (FY2021) outlines the remuneration arrangements of the Group in accordance with the requirements of the *Corporations Act 2001* (Cth)*, as amended (the Act).* This information has been audited as required by section 308(3C) of the Act.

The remuneration report is presented under the following sections:

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

A. Directors and Key Management Personnel

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

Directors

Current Directors:

Mr Michael (Mick) McCormack	Non-executive Chair (appointed 1 September 2020)
Mr Leon Devaney	Managing Director and Chief Executive Officer
Mr Stuart Baker	Non-executive Director
Mr Stephen Gardiner	Non-executive Director (appointed 1 July 2021)
Ms Katherine Hirschfeld AM	Non-executive Director
Dr Agu Kantsler	Non-executive Director

Former Directors:

Dr Julian Fowles	Non-executive Director (resigned 31 October 2020)
Mr Wrixon Gasteen	Non-executive Chair (resigned 28 November 2020)

Other Key Management Personnel

Mr Ross Evans	Chief Operations Officer
Mr Damian Galvin	Chief Financial Officer
Dr Duncan Lockhart	General Manager Exploration
Mr Robin Polson	Chief Commercial Officer (resigned 30 June 2021)
Mr Jonathan Snape	Chief Commercial Officer (appointed 1 July 2021)
Mr Daniel White	Group General Counsel and Company Secretary

B. Remuneration Overview

Central's remuneration strategy is designed to attract, motivate and retain high performing individuals and is linked to the Group's objectives to build long-term shareholder value. In doing so, Central adopts a pay for performance culture which is balanced by a fair and equitable approach to the retention and motivation of its team. The remuneration strategy incorporates the following metrics:

a. Measuring Central's achievement of its KPI targets and share appreciation performance against its peers

   (Peer company group based on comparative indicators such as market capitalisation, size, complexity of operations and market developments)

b. Adjusting to remuneration best practice and movements in relevant labour markets

c. Linking internal strategies to improved shareholder value through achievement of appropriate KPIs.

B. Remuneration Overview (continued)

Financial Year 2021 Summary of fixed and variable remuneration outcomes	
No general salary increases in FY2021	Reflecting market conditions in mid-2020, a pay freeze was implemented for the July 2020 pay review, resulting in no general salary increases for FY2021. As at 1 July 2021, a 2% inflationary pay rise will apply to eligible employees for FY2022. In addition, employees will benefit from the statutory increase in compulsory superannuation from 9.5% to 10%.
STIP	Achievement of Company-wide and individual KPIs resulted in payment of an average 67% of the maximum STIP to eligible employees.
LTIP Vesting	The vesting rate for Share Rights issued under the Long Term Incentive Plan for the three year period ending 30 June 2021 was 31.5%, but may, at the Board's discretion, be eligible for retesting at 31 December 2021.

C. Remuneration Policy

The remuneration policy of the Company is to pay its Directors and executives amounts in line with employment market conditions relevant to the oil and gas industry whilst reflecting Central's specific circumstances. The Company's remuneration practices and, in particular, its short term and long term incentive plans are focussed on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, the major component of executive incentives has been the Employee Rights Plan/Long Term Incentive Plan (LTIP) and the Executive Share Option Plan (ESOP) rather than the Short Term Incentive Plan (STIP).

It is proposed that from FY2022, executives will participate in a revised incentive plan that will combine both short term annual KPIs and a longer-term, equity-based component (refer Section H below).

For periods up to and ending on 30 June 2021, the remuneration of directors and executives consisted of the following key elements:

Non-executive directors:

1. Fees including statutory superannuation; and
2. No participation in short or long term incentive schemes.

Executives, including executive directors:

1. Annual salary and non-monetary benefits including statutory superannuation;
2. Participation in a Short Term Incentive Plan (performance measured over a 12 month period);
3. Participation in a Long Term Incentive Plans (LTIPs or ESOPs), measured over a 3 year period); and
4. There are no guaranteed base pay increases included in any executive's contract.

D. Remuneration Consultants

The performance of the Company depends upon the quality of its directors and executives and the Company strives to attract, motivate and retain highly qualified and skilled management. Salaries and directors' fees are reviewed at least annually to ensure they remain competitive with the market.

For each annual remuneration review cycle, the Remuneration Committee considers whether to appoint a remuneration consultant and, if so, their scope of work.

No remuneration consultants were engaged for the July 2020 review of remuneration. Guerdon Associates were engaged to provide advice relating to the award of the FY2020 STIP, but they did not provide any specific remuneration recommendation.

The Board appointed Guerdon Associates to provide advice relating to incentive schemes for the FY2022 year, but the reports received did not provide any specific remuneration recommendations.

E. Long Term Incentive Plan – Employee Rights Plan (LTIP)

The LTIP has been a major component of executive incentives and, in developing the Employee Rights Plan, the Board focused on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, vesting conditions have been weighted equally between relative shareholder return and absolute shareholder return over a three year period, aligning executive's reward with share performance against peer companies and also with absolute share price growth.

Key terms and vesting conditions

The Company's LTIP was last approved by shareholders in November 2018 to incentivise eligible employees (Non-Executive Directors are not eligible to participate in the LTIP).

The maximum number of performance rights vested in any year is determined by measuring Central's share price performance compared to a peer group of companies (relative measure) and its absolute share price movement over a three-year cycle.

The following table details the percentage of Share Rights in respect of the three-year performance period ending 30 June 2021 which will vest (Vesting Percentage) as determined by the performance conditions, based on the 20-day VWAP prior to 30 June 2021 of $0.122. The benchmark share price at the start of the performance period was $0.163:

Hurdle	Definition	Hurdle Banding	Vesting Percentage	Result for Plan Year Vesting 30 June 2021
Absolute TSR[1] growth **(50% weighting)**	Company's absolute TSR calculated as at vesting date. This looks to align eligible employees' rewards to shareholder superior returns	Company's Absolute TSR over 3 years	Share Rights Vesting	
		25% pa plus	100%	
		20% to <25% pa	75%	
		15% to <20% pa	50%	
		10% to <15% pa	25%	
		Below 10% pa	0%	●

Hurdle	Definition	Hurdle Banding	Vesting Percentage	Result for Plan Year Vesting 30 June 2021
Relative TSR – E&P[2] **(50% weighting)**	Company's TSR relative to a specific group of exploration and production companies (determined by the Board within its discretion) calculated as at vesting date	Company's Relative TSR	Share Rights Vesting	
		76th percentile and above	100%	
		From 51st to 75th percentile	50% to 99%	● (63%)
		Below 51st percentile	0%	

1 Total shareholder return (i.e. growth in share price plus dividends reinvested).
2 Exploration and Production.

For the purposes of determining the number of Share Rights to vest, the Company's absolute TSR and relative TSR are calculated as at the end of the performance period. The Vesting Percentage for each is determined by reference to the hurdle bandings set out in the above tables. The unvested Share Rights for each applicable hurdle are then multiplied by the Vesting Percentage achieved for that hurdle to determine the total number of Share Rights which vest on the vesting date. Vested Share Rights may then be exercised in accordance with the Employee Rights Plan Rules.

Each vested Share Right can be exercised at the rate of one Share Right for one Ordinary Share in the Company.

Employees must be employed by the Company at the end of the performance period in order for the Share Rights to vest. The maximum number of Share Rights that an employee is granted is a function of the employee's Total Fixed Remuneration (TFR) and the 20 trading days daily volume weighted average sale price of company shares sold on the ASX ending on the trading day prior to the start of the performance period.

If the Company is subject to a Change of Control Event, all unvested Share Rights will immediately vest at 100%, with any performance criteria being waived.

E. Long Term Incentive Plan – Employee Rights Plan (LTIP) (continued)

Details of the LTIP Plan's key terms can be viewed on the Company's website at www.centralpetroleum.com.au/careers/why-work-for-central.

Up until FY2021, this LTIP has provided coverage for various levels of eligible employees which include:

a. The Managing Director who is principally responsible for achievement of Central's strategy:
    i) Up until FY2019 received a LTIP percentage of up to 50% of TFR, subject to shareholder approval; and
    ii) From FY2020 to FY2021 participated in the ESOP (refer Section F below);
b. The Executive Management Team (EMT) received a LTIP percentage up to 30% of their TFR until FY2021, with certain EMT members participating in only the ESOP in FY2020 and FY2021;
c. Eligible employees who are in roles which influence and drive the strategic direction of the Company's business or who are senior managers with responsibility for one or more defined functions, departments or outcomes have been eligible to receive a maximum LTIP percentage of 20% or 30% of TFR until FY2021;
d. Eligible employees who are in roles which are focused on the key drivers of the operational parts of the Company's business have received a maximum LTIP percentage of 10% of TFR up until FY2021; and
e. All other eligible employees are integral to the success of the Company obtaining its goals and objectives and may participate in the Central Petroleum $1,000 Exempt Plan.

Conditions of the Central Petroleum $1,000 Exempt Plan include:

1. Share Rights can only be dealt with upon vesting at the end of the three-year service period; and
2. No performance conditions apply.

In 2021, Central conducted an external review of the effectiveness of the LTIP in providing a relevant incentive to all levels of personnel. The review took into account many factors, including the history of rewards under the scheme, taxation implications for employees, near and longer-term drivers of shareholder value and alternative incentive scheme structures used by peers and the broader market. As a result of the review:

i) No further LTIPs will be granted under the existing LTIP structure described above from 1 July 2021;
ii) The Managing Director (subject to shareholder approval) and EMT will be eligible to participate in an Executive Incentive Plan (EIP) from FY2022 (refer Section H below); and
iii) Incentive for employees in categories c, d and e above will be re-weighted to a single STIP opportunity and be eligible to participate in the Central Petroleum $1,000 Exempt Plan.

F. Long Term Incentive Plan – Executive Share Option Plan (ESOP)

On 7 November 2019, shareholders approved the establishment of an ESOP for certain key executives. The ESOP replaced the previous LTIP for participating executives and any Share Options granted under the ESOP replaced the Share Rights that would otherwise have been granted over the next three years under the LTIP.

Key terms and vesting conditions

Each Share Option entitles the participant to subscribe for one Share upon exercise of the Share Option. Share Options will be issued for no consideration, unless otherwise determined by the Board. Share Options do not give any rights to participate in dividends nor to participate in any pro rata issue of securities to Shareholders.

The amount payable upon exercise of each Share Option issued in 2019 is $0.20 (Exercise Price). The Share Options are exercisable from 1 July 2022 until their Expiry Date, 30 June 2023. Once a Share Option is capable of exercise, it may be exercised at any time up until the Expiry Date. Share Options not exercised before the Expiry Date will automatically lapse.

Shares issued on exercise of the Share Options rank equally with the then issued shares of the Company.

All Share Options become exercisable if the Company is subject to a change of control event and in the event that the Share Options have not been exercised before a scheme of arrangement record date or issue of compulsory acquisition notice in the case of a takeover, the Company will cancel the Share Options and pay a settlement fee to the participant of the greater of 5 cents per Share Option or an amount equal to the consideration offered under the scheme of arrangement or takeover bid minus the Exercise Price.

F. Long Term Incentive Plan – Executive Share Option Plan (ESOP) (continued)

All of a participant's Share Options will lapse on the earliest to occur of:

(i) the Expiry Date (as stipulated in the offer); or

(ii) unless otherwise stated in the offer, the date that the Board determines that any service or performance conditions stipulated in the offer as applying to the Share Options cannot be met.

A participant's Share Options will lapse if a Participant ceases to be an employee, except in certain circumstances at the Board's discretion. The number of Share Options which will lapse is a function of the number of days between 1 July 2019 and the participant's termination date as a proportion of the total days between 1 July 2019 and 1 July 2022.

Unless otherwise determined by the Board, a Share Option will immediately lapse if the participant purports to transfer, assign, mortgage, charge, encumber sell or otherwise dispose of the Share Option.

G. Short Term Incentive Plan (STIP)

The Short Term Incentive Plan (STIP) is a performance based plan comprising a matrix of Corporate and Individual Key Performance Indicators (KPIs) for eligible employees.

The Company's Board sets the maximum award achievable in any year under the STIP (normally expressed as a percentage of TFR), which is contingent on the achievement of the KPIs. The KPIs are set at the beginning of each year to incentivise staff to achieve the goals in the next year that the Board consider are key to Central's near-term performance and longer-term strategic direction. Neither the Board nor the Company guarantee any payment from the STIP, nor do they guarantee any performance level of the Company in future years.

Participation in the STIP, or the provision of any Company security, does not form part of the participating employee's remuneration for the purposes of determining payments in lieu of notice of termination of employment, severance payments, leave entitlements, or any other compensation payable to a participating employee upon the termination of employment (unless the Board otherwise determines).

Key terms and conditions

The Financial Year 2021 STIP (FY2021 STIP) has been holistically designed to recognise and reward individual effort through connecting individual KPIs and corporate KPIs.

	Percent Allocation of STIP	
KPI Category	Maximum	Achieved
Corporate KPIs	50 %	25.62 %
Safety and Environment KPI's	10 %	9.38 %
Individual KPIs	40 %	32.00 % (avg)
	100 %	67.00 % (avg)

Employees could earn a maximum of 10% of TFR from the FY2021 STIP.

Corporate KPIs for FY2021 included:

Objective	Weighting	Performance Outcome for FY2021			
		0%	50%	75%	100%
Revenue Assessed against budget	25%			●	
Total Cost[1] Total company operating and capital expenditure for agreed scope of works Assessed against budget	25%				●
Exploration (Dingo Deep & PV Deep) Assessed against budget, commercial viability, schedule and timing hurdles	20%	●			
Range Gas Project Assessed against budget, schedule and timing hurdles	10%			●	
Amadeus to Moomba Gas Pipeline (AMGP) Assessed against progress on milestones	20%	●			

[1] Not rewarded for works that were essential but not completed, e.g. capital project delay or deferral

G. Short Term Incentive Plan (STIP) (continued)

Safety and Environment KPIs for FY2021 included:

Objective	Weighting	Performance Outcome for FY2021 0%	50%	75%	100%
Traditional Owner cultural heritage	25%				●
***Safety:** Total Recordable Incident Frequency Rate (TRIFR)	25%			●	
Environment: Recordable environmental incidents	25%				●
Alice Springs local and Indigenous employment	25%				●

Summary Performance of Company-wide KPI's	Maximum	FY2021 Outcome
Corporate	50% of STI	51.25% (or 25.63 out of a possible 50)
Safety and Environment	10% of STI	93.75% (or 9.38 out of a possible 10)
Total Corporate, Safety & Environment	60% of STI	58.33% (or 35 out of a possible 60)

Individual KPIs provide significant relevance to each role in each department, and for FY2021 were assessed as achieving an average of 80% (or an average of 32 out of a possible 40). Notwithstanding difficult business conditions in FY2021, after assessment of the achievement of the KPIs above and the Company's performance during the year, eligible employees were entitled to receive, on average, 67% of their maximum STIP bonus. The STIP bonuses were paid in cash in July 2021.

STIP starting FY2022

Following a review of the Company's incentive plans, from 1 July 2021 the Short Term Incentive Plan (STIP) will operate with three levels of participation for eligible employees, each with a different level of maximum reward:

STIP participation level (Starting FY2022)	Maximum % of TFR
1	30 %
2	20 %
3	10 %

The maximum STIP % available has increased from previous years for some eligible employees as they will no longer be eligible to receive grants under the LTIP (apart from the Central Petroleum $1,000 Plan).

At the start of each performance period, the CEO will nominate a level of participation for each eligible employee after considering factors such as the eligible employee's:

a) Role and responsibilities;
b) Involvement in strategic and operational aspects of management;
c) Ability to be a key driver of the operational parts of the Company's business; and
d) Ability to influence the Company's performance.

From 1 July 2021, the CEO and executives who participate in the EIP will not be eligible to participate in the STIP (refer Section H of this report).

At the Board's discretion the STIP award may be paid through a combination of cash and/or Company securities.

H. Executive Incentive Plan (EIP)

Following a review of the Company's incentive plans, Central will establish an EIP for key executives to align executive performance with the achievement of key objectives for the Plan Year commencing 1 July 2021 and continuing for subsequent Plan Years commencing 1 July 2022 and 1 July 2023. No further grants will be made to participating executives under the existing LTIP, ESOP and STIP as these plans are effectively being replaced by the EIP.

As the ESOP Share Options granted in 2019 were granted as incentives for three years, including the year commencing 1 July 2021, to avoid a double reward for that year, the maximum reward that can be obtained under the EIP will be proportionately reduced by the value of any ESOP Share Options that are subsequently exercised.

Key terms and vesting conditions

The EIP is an integrated incentive with both short term and long term components. The value of the EIP that is awarded is determined at the end of the first 12 month performance period upon measurement of performance against Board established KPI targets for that year. The incentive awarded is then split into two components:

a) 33% is paid at that time (i.e. at the end of the initial 12 month performance period); and

b) The 67% balance of the awarded incentive value is granted as Service Rights that vest over the next three years in equal tranches beginning 12 months after the end of the initial 12 month performance period.

The maximum opportunity for the executive team as a percentage of TFR is:

- CEO: 120%
- Other eligible executives: 80%

The Board has ultimate discretion to assess the achievement of the KPI targets, including application of an overriding good conduct 'gateway'. The Board can determine whether the award payment at the end of the first performance period is paid as cash or equivalent Company Securities. Vested Service Rights may be exercised in accordance with the Employee Rights Plan Rules.

The number of Service Rights awarded for any single Plan Year is determined by reference to Central's volume weighted average share price for the 20 trading days immediately following the release of Central's Quarterly Activity Statement for the performance period ending 30 June.

The Service Rights are the right to acquire fully paid ordinary shares for no exercise price at the end of the vesting period and can be exercised up to five years from the grant date. To maintain alignment with shareholders, the Service Rights have a dividend entitlement whereby the Service Rights convert to one share plus an additional number of shares equal in value to the dividends paid during the period from grant to exercise.

Service Rights do not automatically vest on change of control, but vest as a function of the service period and the circumstances of the change in control, subject to discretion of the Board. Any Service Rights that vest on a change in control are subject to automatic exercise.

Upon cessation of employment the Service Rights remain on foot to be tested in the normal course with the Board having the discretion to forfeit, having regard for the prevailing facts and circumstances at the time of cessation.

Details of remuneration for the Directors and key management personnel of Central Petroleum Limited and the Consolidated Entity are set out in Section J of this report.

I. Realised Remuneration

Table 1 identifies the Actual Remuneration received by Senior Executives in respect of the 2021 financial year. Realised Remuneration reflects the take home remuneration of the Executive and includes:

- Total fixed remuneration inclusive of company superannuation contributions;
- Any Short Term Incentive awarded as cash for the financial year but paid after the end of the financial year;
- Any Short Term Incentive awarded as share rights in lieu of cash for the financial year, and granted after the end of the financial year valued at the cash equivalent amount (but excluding any share rights which do not immediately vest); and
- The value of LTIP share rights vesting (if any) in respect of the three-year period ending 30 June, valued at the year-end share price (2021: 11.5 cents per share, 2020: 8.1 cents per share).

The table below has been provided to assist shareholders to understand the remuneration received in respect of each financial year ending 30 June. The table is a voluntary disclosure and as such has not been prepared in accordance with the disclosure requirements of the Accounting Standards or Corporations Act 2001. See Table 2 for Executive KMP remuneration in accordance with these requirements.

Table 1: Realised Remuneration

	Year	Total Fixed Remuneration[1] $	STI (Cash) $	Other Benefits[2] $	LTI Vested as Shares[3] $	Total $
Current Executive KMP						
Leon Devaney	**2021**	**612,061**	**42,231**	**7,635**	**66,549**	**728,476**
	2020	612,061	—	8,380	—	620,441
Ross Evans	**2021**	**500,404**	**34,527**	**7,635**	**28,214**	**570,780**
	2020	500,404	—	8,380	—	508,784
Damian Galvin[4]	**2021**	**330,001**	**21,449**	**7,635**	**—**	**359,085**
	2020	289,162	—	7,039	—	296,201
Duncan Lockhart	**2021**	**400,001**	**25,999**	**7,635**	**—**	**433,635**
	2020	400,472	—	8,332	—	408,804
Robin Polson	**2021**	**335,132**	**21,783**	**7,635**	**21,861**	**386,411**
	2020	335,132	—	8,380	—	343,512
Daniel White	**2021**	**444,080**	**28,864**	**7,635**	**29,160**	**509,739**
	2020	444,080	—	8,380	—	452,460
Total Executive KMP	**2021**	**2,621,679**	**174,853**	**45,810**	**145,784**	**2,988,126**
	2020	2,581,311	—	48,891	—	2,630,202

1 Total Fixed Remuneration includes salaries, fees and superannuation contributions.
2 Includes car parking and other fringe benefits.
3 Long Term Incentive Vested as Shares comprises any LTI from prior years that was awarded or is expected to be awarded for the three-year period ending 30 June and valued at that date.
4 Damian Galvin commenced 5 August 2019.

J. Remuneration Details – Statutory tables

Table 2: Remuneration of Directors and Key Management Personnel

		Short-Term			Post-Employment		Long-Term Benefits	Share-Based Payments		Variable Remuneration
		Salary/ Fees $	STI[1] $	Non-Monetary Benefits $	Superannuation Contributions $	Termination Benefits $	LSL (Accrued) $	Rights & Options[2] $	Total $	Percent of Remuneration %
Non-Executive Directors										
Stuart Baker	**2021**	**85,000**	—	—	**8,075**	—	—	—	**93,075**	—
	2020	86,250	—	—	8,194	—	—	—	94,444	—
Katherine Hirschfeld	**2021**	**85,833**	—	—	**8,154**	—	—	—	**93,987**	—
	2020	90,000	—	—	8,550	—	—	—	98,550	—
Agu Kantsler[3]	**2021**	**78,333**	—	—	**7,442**	—	—	—	**85,775**	—
	2020	3,111	—	—	296	—	—	—	3,407	—
Michael McCormack[4]	**2021**	**107,500**	—	—	**10,212**	—	—	—	**117,712**	—
	2020	—	—	—	—	—	—	—	—	—
Former Non-Executive Directors										
Julian Fowles[5]	**2021**	**26,667**	—	—	**2,533**	—	—	—	**29,200**	—
	2020	81,604	—	—	7,752	—	—	—	89,356	—
Wrixon Gasteen[6]	**2021**	**64,167**	—	—	**6,096**	—	—	—	**70,263**	—
	2020	150,000	—	—	14,250	—	—	—	164,250	—
Martin Kriewaldt[7]	**2021**	—	—	—	—	—	—	—	—	—
	2020	26,667	—	—	2,533	—	—	—	29,200	—
Sub-total	**2021**	**447,500**	—	—	**42,512**	—	—	—	**490,012**	—
	2020	437,632	—	—	41,575	—	—	—	479,207	—
Executives										
Leon Devaney	**2021**	**623,324**	**42,231**	**7,635**	**21,694**	—	**11,221**	**341,098**	**1,047,203**	**37%**
	2020	601,381	10,941	8,380	21,003	—	12,688	219,916	874,309	26%
Ross Evans	**2021**	**499,881**	**34,527**	**7,635**	**21,694**	—	**8,690**	**223,072**	**795,499**	**32%**
	2020	485,955	8,945	8,380	21,003	—	6,710	176,225	707,218	26%
Damian Galvin[8]	**2021**	**318,460**	**21,449**	**7,635**	**21,694**	—	**4,218**	**130,751**	**504,207**	**30%**
	2020	277,551	5,363	7,039	19,779	—	2,920	99,694	412,346	25%
Duncan Lockhart	**2021**	**392,139**	**25,999**	**7,635**	**21,694**	—	**5,308**	**158,892**	**611,667**	**30%**
	2020	384,464	6,708	8,332	21,003	—	4,073	120,841	545,421	23%
Robin Polson	**2021**	**318,593**	**21,783**	**7,635**	**21,694**	—	**5,870**	**134,477**	**510,052**	**31%**
	2020	329,546	5,446	8,380	21,003	—	4,534	120,219	489,128	26%
Daniel White	**2021**	**444,673**	**28,864**	**7,635**	**21,694**	—	**8,140**	**123,785**	**634,791**	**24%**
	2020	430,904	7,216	8,380	21,003	—	9,180	109,385	586,068	20%
Sub-total	**2021**	**2,597,070**	**174,853**	**45,810**	**130,164**	—	**43,447**	**1,112,075**	**4,103,419**	**31%**
	2020	2,509,801	44,619	48,891	124,794	—	40,105	846,280	3,614,490	25%
Total Remuneration	**2021**	**3,044,570**	**174,853**	**45,810**	**172,676**	—	**43,447**	**1,112,075**	**4,593,431**	**28%**
	2020	2,947,433	44,619	48,891	166,369	—	40,105	846,280	4,093,697	22%

1 Short term incentives are unpaid at the end of the financial year. Amounts are shown in respect of the performance period to which they relate. Subsequent to the end of the 2020 financial year, the Board decided that the 2020 STI was to be awarded as deferred share rights which are expensed over the performance period, which includes the year to which the bonus relates and the subsequent 3-year vesting period.

2 The fair values of share rights granted are valued using methodology that takes into account market and peer performance hurdles. The values of rights are calculated at the date of grant using a Black Scholes valuation model and Monte Carlo simulations and an agreed comparator group to assess relative total shareholder return. The values are allocated to each reporting period evenly over the period from grant date to vesting date. In the event that rights are cancelled for failure to meet the required service period or are not retained on termination of employment, any amounts previously expensed as share based payments are reversed as negative amounts.

3 Agu Kantsler was appointed 15 June 2020.

4 Mr McCormack commenced 1 September 2020

5 Julian Fowles resigned 31 October 2020.

6 Wrix Gasteen resigned 28 November 2020.

7 Martin Kriewaldt resigned 2 September 2019.

8 Damian Galvin commenced 5 August 2019.

J. Remuneration Details – Statutory tables (continued)

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during FY2021:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
24 Jul 2020[1]	30 Jun 2025	$0.065	Nil	$0.089	72%	0.43%	—
11 Nov 2020[2]	30 Jun 2025	$0.130	Nil	$0.130	N/A	N/A	—

1 LTIP Rights for the plan year commencing 1 July 2020.
2 Deferred Share rights awarded in lieu of cash under the STIP for the year ended 30 June 2020.

The following factors and assumptions were used in determining the fair value of share rights granted during FY2020:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
09 Aug 2019[1]	13 Sep 2024	$0.155	Nil	$0.155	N/A	N/A	—
23 Aug 2019[2]	30 Jun 2024	$0.155	Nil	$0.190	98%	0.70%	—
13 Sep 2019[3]	08 Dec 2022	$0.150	Nil	$0.200	N/A	N/A	—
07 Nov 2019[4]	12 Nov 2024	$0.119	Nil	$0.170	95%	0.94%	—

1 STIP Rights fully vested on issue – valued at market price at grant date.
2 LTIP Rights for plan year commencing 1 July 2019.
3 Adjustment to number of LTIP Rights for plan year commencing 1 July 2016 – valued at the market price of the known vesting %.
4 LTIP rights issued to L Devaney in respect of the plan year commencing 1 July 2018.

Table 3: Short Term Incentives Awarded

		Maximum $	Awarded[1] $	Awarded[1] %	Forfeited %
Leon Devaney	**2021**	**61,206**	**42,231**	**69%**	**31%**
	2020	61,206	43,762	71%	29%
Ross Evans	**2021**	**50,040**	**34,527**	**69%**	**31%**
	2020	50,040	35,779	72%	28%
Damian Galvin	**2021**	**33,000**	**21,449**	**65%**	**35%**
	2020	33,000	21,450	65%	35%
Duncan Lockhart	**2021**	**40,000**	**25,999**	**65%**	**35%**
	2020	40,047	26,832	67%	33%
Robin Polson	**2021**	**33,513**	**21,783**	**65%**	**35%**
	2020	33,513	21,784	65%	35%
Daniel White	**2021**	**44,408**	**28,864**	**65%**	**35%**
	2020	44,408	28,865	65%	35%
Total	**2021**	**262,167**	**174,853**	**67%**	**33%**
	2020	262,214	178,472	68%	32%

1 The FY2020 STIP was settled in the form of share rights with a further 3-year vesting period. Nil% had vested at 30 June 2021.

J. Remuneration Details – Statutory tables (continued)

Table 4: Share Based Compensation – Share Rights Granted to Key Management Personnel during the Year

		Number of Rights Granted	Grant Date	Average Fair Value at Grant Date	Average Exercise Price Per Right	Expiry Date
Leon Devaney	**2021[1]**	**496,171**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2020	1,837,109	07 Nov 19	$0.119	—	12 Nov 24
Ross Evans	**2021[1]**	**405,655**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2020	140,845	09 Aug 19	$0.142	—	13 Sep 24
Damian Galvin	**2021[1]**	**243,198**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2020	—	N/A	N/A	—	N/A
Duncan Lockhart	**2021[1]**	**304,213**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2020	—	N/A	N/A	—	N/A
Robin Polson	**2021[1]**	**246,979**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2020	94,598	09 Aug 19	$0.142	—	13 Sep 24
Daniel White	**2021[1]**	**327,269**	**11 Nov 20**	**$0.130**	**—**	**30 Jun 25**
	2021	**1,510,476**	**24 Jul 20**	**$0.065**	**—**	**30 Jun 25**
	2020	119,077	09 Aug 19	$0.142	—	13 Sep 24
	2020	123,679	13 Sep 19	$0.150	—	08 Dec 22
	2020	983,204	23 Aug 19	$0.155	—	30 Jun 24
Total	**2021**	**3,533,961**				
	2020	3,298,512				

1 Represents FY2020 STIP settled as Equity in the form of deferred share rights.

Table 5: Share Based Compensation – Share Rights Vested to Key Management Personnel during the Year

		Maximum Number of Rights Eligible for Vesting	LTIP Year Commencing	STIP Year Commencing	Number of Rights Vested[1]	Proportion of LTIP Rights Vested[2]	Proportion of LTIP Rights Forfeited
Leon Devaney	**2021**	**1,837,109**	**01 Jul 18**	**N/A**	**578,689**	**31.5%**	**68.5%**
	2020	890,625	01 Jul 17	N/A	—	0.0%	**100.0%**
Ross Evans	**2021**	**778,854**	**01 Jul 18**	**N/A**	**245,339**	**31.5%**	**68.5%**
	2020	140,845	N/A[3]	01 Jul 18	140,845	N/A[3]	**N/A[3]**
Robin Polson	**2021**	**603,491**	**01 Jul 18**	**N/A**	**190,099**	**31.5%**	**68.5%**
	2020	94,598	N/A[3]	01 Jul 18	94,598	N/A[3]	**N/A[3]**
Daniel White	**2021**	**804,984**	**01 Jul 18**	**N/A**	**253,569**	**31.5%**	**68.5%**
	2020	736,319	01 Jul 17	N/A	—	0.0%	**100.0%**
	2020	119,077	N/A[3]	01 Jul 18	119,077	N/A[3]	**N/A[3]**
Total	**2021**	**4,024,438**			**1,267,696**	**31.5%**	**68.5%**
	2020	1,981,464			354,520	0.0%	**100.0%**

1 The number of rights that vested during the 2021 year relates to rights granted in prior financial years under the Long Term Incentive Plan.
2 The proportion of rights vested represents the proportion of the maximum number of rights that were eligible for vesting during the financial year under the Long Term Incentive Plan.
3 Rights issued as part settlement of FY2019 STIP.

J. Remuneration Details – Statutory tables (continued)

Table 6: Share Based Compensation – Options Granted to Key Management Personnel during the Year

		Number of Options Granted	Grant Date	Option Expiry Date	Exercise Price	Fair Value at Grant
Leon Devaney	**2021**	—	—	—	—	—
	2020	5,105,000	07 Nov 19	30 Jun 23	$0.20	$0.087
Ross Evans	**2021**	—	—	—	—	—
	2020	4,170,025	20 Aug 19	30 Jun 23	$0.20	$0.120
Damian Galvin	**2021**	—	—	—	—	—
	2020	2,750,000	20 Aug 19	30 Jun 23	$0.20	$0.120
Duncan Lockhart	**2021**	—	—	—	—	—
	2020	3,333,333	20 Aug 19	30 Jun 23	$0.20	$0.120
Robin Polson	**2021**	—	—	—	—	—
	2020	2,792,758	20 Aug 19	30 Jun 23	$0.20	$0.120
Total	**2021**	—				
	2020	18,151,116				

The values of Options are calculated at the date of grant using a Black Scholes valuation. The following factors and assumptions were used in determining the fair value of Options granted to key management personnel during FY2020:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
20 Aug 2019	30 Jun 2023	$0.120	$0.20	$0.16	78%	0.92%	—
07 Nov 2019	30 Jun 2023	$0.087	$0.20	$0.17	78%	0.85%	—

Share, Rights and Option Holdings of Key Management Personnel

Under the Group's Long Term Incentive Plans, eligible employees may receive:

a) Rights to shares of the Company under the Employee Rights Plan (refer section E of this report); and

b) Options over shares of the Company under the Executive Share Option Plan (refer section F of this report).

Table 7: Vesting profile of Share Rights Holdings of Key Management Personnel

	Grant Date	Type	Maximum Number of Rights Eligible for Vesting at 30 June 2021	Vesting Date[1]	Maximum value yet to vest[2]		
					FY2021	FY2022	FY2023
Leon Devaney	7 Nov 2019	Share Rights – LTIP	1,837,109	30 Jun 2021	—	—	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	496,171	30 Jun 2023	—	—	32,251
Ross Evans	24 Sep 2018	Share Rights – LTIP	642,988	30 Jun 2021	—	—	—
	9 May 2019	Share Rights – LTIP	135,866	30 Jun 2021	—	—	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	405,655	30 Jun 2023	—	—	26,368
Damian Galvin	11 Nov 2020	Deferred Share Rights – STIP[3]	243,198	30 Jun 2023	—	—	15,808
Duncan Lockhart	11 Nov 2020	Deferred Share Rights – STIP[3]	304,213	30 Jun 2023	—	—	19,774
Robin Polson	24 Sep 2018	Share Rights – LTIP	551,132	30 Jun 2021	—	—	—
	9 May 2019	Share Rights – LTIP	52,359	30 Jun 2021	—	—	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	246,979	30 Jun 2023	—	—	16,054
Daniel White	24 Sep 2018	Share Rights – LTIP	735,145	30 Jun 2021	—	—	—
	9 May 2019	Share Rights – LTIP	69,839	30 Jun 2021	—	—	—
	23 Aug 2019	Share Rights – LTIP	983,204	30 Jun 2022	—	53,332	—
	24 Jul 2020	Share Rights - LTIP	1,510,476	30 Jun 2023	—	—	65,454
	11 Nov 2020	Deferred Share Rights – STIP[3]	327,269	30 Jun 2023	—	—	21,272
Total			**8,541,603**		—	**53,332**	**196,981**

1 The earliest vesting date under the relevant plan rules. The final vesting date may be subject to retesting periods, subject to Board discretion.
2 The maximum value of the share rights yet to vest has been determined as the amount of the grant date fair value of the rights that is yet to be expensed. The minimum value to vest is nil, as the rights will be forfeited if the vesting conditions are not met.
3 The FY2020 STIP was awarded as rights to deferred shares instead of cash.

J. Remuneration Details – Statutory tables (continued)

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

Table 8: Share Rights Holdings of Key Management Personnel

Share Rights		Number of Rights Held at Start of Year	Maximum Number Granted as Compensation	Cancelled During the Year	Converted to Shares	Retained on Departure	Number of Rights Held at End of Year (Unvested)
Key Management Personnel							
Leon Devaney	**2021**	**2,727,734**	**496,171**	**(890,625)**	**—**	**N/A**	**2,333,280**
	2020	2,202,158	1,837,109	(233,552)	(1,077,981)	N/A	2,727,734
Ross Evans	**2021**	**778,854**	**405,655**	**—**	**—**	**N/A**	**1,184,509**
	2020	778,854	140,845	—	(140,845)	N/A	778,854
Damian Galvin	**2021**	**—**	**243,198**	**—**	**—**	**N/A**	**243,198**
	2020	N/A	—	—	—	N/A	—
Duncan Lockhart	**2021**	**—**	**304,213**	**—**	**—**	**N/A**	**304,213**
	2020	N/A	—	—	—	N/A	—
Robin Polson	**2021**	**603,491**	**246,979**	**—**	**—**	**N/A**	**850,470**
	2020	603,491	94,598	—	(94,598)	N/A	603,491
Daniel White	**2021**	**2,524,507**	**1,837,745**	**(736,319)**	**—**	**N/A**	**3,625,933**
	2020	2,830,969	1,225,960	(353,337)	(1,179,085)	N/A	2,524,507
Total	**2021**	**6,634,586**	**3,533,961**	**(1,626,944)**	**—**	**—**	**8,541,603**
	2020	6,415,472	3,298,512	(586,889)	(2,492,509)	—	6,634,586

The number of Options to ordinary shares in the Company under the Executive Share Option Plan held during the financial year by key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

Table 9: Options Holdings of Key Management Personnel

Share Options		Number of Options Held at Start of Year	Options Granted as Compensation	Exercise Price	Expiry Date	Cancelled or Expired During the Year	Exercised and Converted to Shares	Retained on Departure	Number of Options Held at End of Year (Unvested)
Key Management Personnel									
Leon Devaney	**2021**	**5,105,000**	**—**	**—**	**—**	**—**	**—**	**N/A**	**5,105,000**
	2020	—	5,105,000	$0.20	30 Jun 23	—	—	N/A	5,105,000
Ross Evans	**2021**	**4,170,025**	**—**	**—**	**—**	**—**	**—**	**N/A**	**4,170,025**
	2020	—	4,170,025	$0.20	30 Jun 23	—	—	N/A	4,170,025
Damian Galvin	**2021**	**2,750,000**	**—**	**—**	**—**	**—**	**—**	**N/A**	**2,750,000**
	2020	—	2,750,000	$0.20	30 Jun 23	—	—	N/A	2,750,000
Duncan Lockhart	**2021**	**3,333,333**	**—**	**—**	**—**	**—**	**—**	**N/A**	**3,333,333**
	2020	—	3,333,333	$0.20	30 Jun 23	—	—	N/A	3,333,333
Robin Polson	**2021**	**2,792,758**	**—**	**—**	**—**	**—**	**—**	**N/A**	**2,792,758**
	2020	—	2,792,758	$0.20	30 Jun 23	—	—	N/A	2,792,758
Total	**2021**	**18,151,116**	**—**			**—**	**—**	**—**	**18,151,116**
	2020	—	18,151,116			—	—	—	18,151,116

REMUNERATION REPORT
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J. Remuneration Details – Statutory tables (continued)

Table 10: Shareholdings of Key Management Personnel

Ordinary Shares		Held at Beginning of Year	Held at Date of Appointment	SPP & On Market Purchase	Exercise of Rights	Net Change Other	Held at Date of Departure	Held at End of Year
Non-Executive Directors								
Stuart Baker	**2021**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2020	—	N/A	—	—	—	N/A	—
Julian Fowles[1]	**2021**	**100,000**	**N/A**	**—**	**—**	**—**	**100,000**	**N/A**
	2020	—	N/A	100,000	—	—	N/A	100,000
Wrixon Gasteen[2]	**2021**	**793,337**	**N/A**	**—**	**—**	**—**	**793,337**	**N/A**
	2020	293,337	N/A	500,000	—	—	N/A	793,337
Katherine Hirschfeld	**2021**	**760,850**	**N/A**	**—**	**—**	**—**	**N/A**	**760,850**
	2020	200,000	N/A	560,850	—	—	N/A	760,850
Agu Kantsler[3]	**2021**	**—**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2020	N/A	—	—	—	—	N/A	—
Martin Kriewaldt[4]	**2021**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2020	1,100,000	N/A	—	—	—	1,100,000	N/A
Michael McCormack[5]	**2021**	**N/A**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2020	N/A	N/A	—	—	—	N/A	N/A
Sub-total	**2021**	**1,654,187**	**—**	**—**	**—**	**—**	**893,337**	**760,850**
	2020	1,593,337	—	1,160,850	—	—	1,100,000	1,654,187
Other Key Management Personnel								
Leon Devaney	**2021**	**2,606,757**	**N/A**	**—**	**—**	**—**	**N/A**	**2,606,757**
	2020	1,053,776	N/A	475,000	1,077,981	—	N/A	2,606,757
Ross Evans	**2021**	**140,845**	**N/A**	**—**	**—**	**—**	**N/A**	**140,845**
	2020	—	N/A	—	140,845	—	N/A	140,845
Damian Galvin[6]	**2021**	**141,000**	**N/A**	**—**	**—**	**—**	**N/A**	**141,000**
	2020	N/A	71,000	70,000	—	—	N/A	141,000
Duncan Lockhart	**2021**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2020	—	N/A	—	—	—	N/A	—
Robin Polson	**2021**	**94,598**	**N/A**	**—**	**—**	**—**	**N/A**	**94,598**
	2020	—	N/A	—	94,598	—	N/A	94,598
Daniel White	**2021**	**2,309,074**	**N/A**	**—**	**—**	**—**	**N/A**	**2,309,074**
	2020	1,129,989	N/A	—	1,179,085	—	N/A	2,309,074
Sub-total	**2021**	**5,292,274**	**—**	**—**	**—**	**—**	**—**	**5,292,274**
	2020	2,183,765	71,000	545,000	2,492,509	—	—	5,292,274
Total KMP	**2021**	**6,946,461**	**—**	**—**	**—**	**—**	**893,337**	**6,053,124**
	2020	3,777,102	71,000	1,705,850	2,492,509	—	1,100,000	6,946,461

1 Julian Fowles resigned 31 October 2020.
2 Wrixon Gasteen resigned 28 November 2020.
3 Agu Kantsler was appointed 15 June 2020.
4 Martin Kriewaldt resigned 2 September 2019.
5 Michael McCormack was appointed Director on 1 September 2020.
6 Damian Galvin commenced 5 August 2019.

K. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity as of 1 July 2021 are as follows:

Table 11: Key Management Personnel Service Agreements

Name	Position	Term of agreement expires	Total Annual Fixed Remuneration[1]	Notice period [2]
Leon Devaney	Managing Director & Chief Executive Officer	01 Jul 2022	$625,750	6 months
Ross Evans	Chief Operations Officer	01 Dec 2022	$511,860	6 months
Damian Galvin	Chief Financial Officer	05 Aug 2022	$338,050	6 months
Duncan Lockhart	General Manager Exploration	08 Jul 2022	$409,450	6 months
Jonathan Snape	Chief Commercial Officer	Full time permanent	$330,000	3 months
Daniel White	Group General Counsel & Company Secretary	30 Nov 2021	$454,410	3 months

1 Total Annual Fixed Remuneration includes compulsory superannuation contributions.
2 In certain exceptional circumstances (such as breach or gross misconduct) a shorter notice period applies.

L. Non-Executive Director Fee Arrangements

The Company has engaged all Directors pursuant to written service agreements. The terms of appointment are subject to the Company's constitution. The Company maintains an appropriate level of Directors' and Officers' Liability Insurance and provide rights relating to indemnity, insurance, and access to documents.

The table below summarises the Non-Executive Director fees for FY2021.

Board Fees (per annum)	
Chair	$130,000
Non-Executive Director	$70,000

FY2021 Committee Fees (per annum)		
Audit & Financial Risk	Chair	$10,000
	Member	$5,000
Remuneration & Nominations	Chair	$10,000
	Member	$5,000
Risk & Sustainability	Chair	$10,000
	Member	$5,000

The directors also receive superannuation benefits in accordance with legislative requirements.

Signed in accordance with a resolution of the directors:

Michael McCormack
Chair

21 September 2021

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2021, I declare that to the best of my knowledge and belief, there have been:

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

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

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

Marcus Goddard
Partner
PricewaterhouseCoopers

Brisbane
21 September 2021

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FINANCIAL REPORT

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the operating and financial review on pages 3 to 27. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 21 September 2021. The Directors have the power to amend and reissue the financial statements.

Through the use of the internet, we have ensured that our corporate reporting is timely and complete. ASX releases, financial reports and other information are available via the links on our website: www.centralpetroleum.com.au.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2021

	NOTE	2021 $'000	2020 $'000
Revenue from contracts with customers – sale of hydrocarbons	2	59,827	65,046
Cost of sales		(28,852)	(33,386)
Gross profit		**30,975**	**31,660**
Other income	3	155	8,610
Exploration expenditure		(7,739)	(5,277)
Employee benefits and associated costs net of recoveries	4(b)	(2,180)	(3,668)
Share based employment benefits	32(d)	(1,862)	(1,937)
General and administrative expenses net of recoveries		(924)	(1,110)
Depreciation and amortisation	4(a)	(12,503)	(16,257)
Impairment expense	4(c)	—	(177)
Finance costs	4(a)	(5,671)	(6,433)
Profit before income tax		**251**	**5,411**
Income tax (expense)/credit	5	—	—
Profit for the year		**251**	**5,411**
Other comprehensive profit/(loss) for the year, net of tax		—	—
Total comprehensive profit for the year		**251**	**5,411**
Total comprehensive profit attributable to members of the parent entity		**251**	**5,411**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic earnings per share (cents)	23	**0.03**	**0.75**
Diluted earnings per share (cents)	23	**0.03**	**0.75**

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET
AS AT 30 JUNE 2021

	NOTE	2021 $'000	2020 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	37,159	25,918
Trade and other receivables	8	7,111	6,774
Inventories	9	1,621	2,581
Assets classified as held for sale	10	57,968	—
Total current assets		103,859	35,273
Non-current assets			
Property, plant and equipment	11	53,988	107,845
Right of use assets	12	1,455	1,059
Exploration assets	13	8,397	8,722
Intangible assets	14	302	312
Other financial assets	15	4,218	2,656
Goodwill	16	1,953	3,906
Total non-current assets		70,313	124,500
Total assets		**174,172**	**159,773**
LIABILITIES			
Current liabilities			
Trade and other payables	17	10,491	5,287
Deferred revenue	2(b)	5,244	10,891
Borrowings	18(a)	36,000	6,964
Lease liabilities	12	517	608
Provisions	19	3,918	4,774
Liabilities directly associated with assets classified as held for sale	10	39,436	—
Total current liabilities		95,606	28,524
Non-current liabilities			
Deferred revenue	2(b)	15,697	22,964
Borrowings	18(b)	30,809	63,809
Lease liabilities	12	992	618
Provisions	19	27,379	42,276
Total non-current liabilities		74,877	129,667
Total liabilities		**170,483**	**158,191**
Net assets		**3,689**	**1,582**
EQUITY			
Contributed equity	20 (a)	197,776	197,776
Reserves	21	29,094	27,238
Accumulated losses	22	(223,181)	(223,432)
Total equity		**3,689**	**1,582**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2021

	Contributed Equity $'000	Reserves $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2019	**197,776**	**25,310**	**(228,843)**	**(5,757)**
Total profit for the year	—	—	5,411	5,411
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	5,411	5,411
Transactions with owners in their capacity as owners				
Share based payments	—	1,937	—	1,937
Share issue costs	—	(9)	—	(9)
	—	1,928	—	1,928
Balance at 30 June 2020	**197,776**	**27,238**	**(223,432)**	**1,582**
Total profit for the year	—	—	251	251
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	251	251
Transactions with owners in their capacity as owners				
Share based payments	—	1,862	—	1,862
Share issue costs	—	(6)	—	(6)
	—	1,856	—	1,856
Balance at 30 June 2021	**197,776**	**29,094**	**(223,181)**	**3,689**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2021

	NOTE	2021 $'000	2020 $'000
Cash flows from operating activities			
Receipts from customers		65,539	62,945
Interest received		82	172
Other income		73	6
Government grants		1,367	(133)
Interest and borrowing costs		(3,924)	(5,089)
Payments for exploration expenditure		(5,461)	(3,142)
Payments to other suppliers and employees		(33,540)	(39,032)
Net cash inflow from operating activities	28	24,136	15,727
Cash flows from investing activities			
Payments for property, plant and equipment		(6,489)	(3,224)
Proceeds from sale of property, plant and equipment		9	76
Proceeds and deposits for the disposal of exploration permits		—	7,713
(Lodgement)/redemption of security deposits and bonds		(1,562)	115
Net cash (outflow)/inflow from investing activities		(8,042)	4,680
Cash flows from financing activities			
Payments for the issue of securities		(5)	(10)
Repayment of borrowings	29(b)	(4,000)	(11,501)
Transaction costs related to borrowings		(220)	(236)
Principal elements of lease payments	29(b)	(622)	(548)
Net cash outflow from financing activities		(4,847)	(12,295)
Net increase in cash and cash equivalents		**11,247**	**8,112**
Cash and cash equivalents at the beginning of the financial year		**25,918**	**17,806**
Cash and cash equivalents at the end of the financial year	7	**37,165**	**25,918**

The accompanying notes form part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated. The financial statements are for the consolidated entity consisting of Central Petroleum Limited ("the Company") and its subsidiaries (collectively "the Group" or "the Consolidated Entity").

(a) Basis of Preparation

These general-purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board and the *Corporations Act 2001*. They present reclassified comparative information where required for consistency with the current year's presentation or where otherwise stated. Central Petroleum Limited is a for-profit entity for the purpose of preparing the financial statements.

Rounding of Amounts
The company is of a kind referred to in ASIC Legislative Instrument 2016/191, relating to the 'rounding off' of amounts in the financial statements. Amounts in the financial statements have been rounded off in accordance with the instrument to the nearest thousand dollars, or in certain cases, the nearest dollar.

(i) Going Concern

The Directors have prepared the financial statements on a going concern basis which contemplates continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business.

The Group recorded a net profit for the year of $251,000, had a net positive cash flow from operations of $24,136,000 and had an overall net current asset position at 30 June 2021 of $8,253,000, inclusive of assets held for sale and liabilities directly associated with those assets. The net current assets include $5,244,000 of deferred revenue liabilities which will be settled via the physical delivery of gas rather than as any cash payment to the customer. The Board and management monitor the Group's cash flow requirements to ensure it has sufficient funds to meet its contractual commitments and adjusts its spending, particularly with respect to discretionary exploration activity and corporate expenditures.

Supported by the cash assets at 30 June 2021 of $37,159,000, and expected operating cashflows, the Group forecasts that over at least the next 12 months, it will have sufficient funds to meet its commitments and continue to pay its debts as and when they fall due. To date the Group has been successful in funding new projects through a combination of borrowings, gas presales, farmouts and equity from new and existing shareholders. The partial asset sale, which is expected to complete on 1 October 2021, includes deferred consideration of $40,000,000 which will fund Central's share of selected future capital exploration and development costs in those areas for at least the next 12 months.

Current borrowings of $36,000,000 includes $29,000,000 to be repaid from the proceeds of the partial asset sale upon completion. This would otherwise have been classified as a non-current borrowing, but due to the asset sale, as at 30 June 2021 there is not an unconditional right to defer settlement of this amount for at least 12 months and it has been classified as a current borrowing. If the transaction does not complete, the $29,000,000 would revert to being payable on 30 September 2022. Central and its secured lender have agreed to the necessary revisions to the financing arrangements to accommodate the partial asset sale and loan prepayment. Management and the Board are considering various refinancing / maturity extension options and are confident that new financing arrangements will be in place before expiry of the existing loan facility in September 2022.

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

(ii) Compliance with IFRS

The consolidated financial statements of the Central Petroleum Limited Group also comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

(iii) Early Adoption of Standards

The Group has not applied any pronouncements to the annual reporting period beginning on 1 July 2020 where such application would result in them being applied prior to them becoming mandatory.

(iv) Historical Cost Convention

These financial statements have been prepared under the historical cost convention.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

(v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty

In the application of the Group's accounting policies, management is required to make judgements, estimates and assumptions regarding carrying values of assets and liabilities that are not readily apparent from other sources. The estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements. Actual results may differ from these estimates. Key judgements in applying the entity's accounting policies are required in the following areas:

Rehabilitation Obligations

The Group recognises any obligations for removal and restoration that are incurred during a particular period as a consequence of having undertaken exploration and evaluation activity. The Group makes provision for future restoration expenditure relating to work previously undertaken based on management's estimation of the work required and by obtaining cost estimates from relevant experts. Further information on the nature and carrying amount of restoration and rehabilitation obligations can be found in Note 19.

Share-based Payments

The Group is required to use assumptions in respect of its fair value models, and the variable elements in these models, used in attributing a value to share based payments. The Directors have used a model to value options and rights, which requires estimates and judgements to quantify the inputs used by the model. Further information on the assumptions used in determining the fair value of rights and options granted during the year can be found in Section I of the Remuneration Report.

Capitalised Exploration and Evaluation Expenditure

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the lease itself or, if not, whether it successfully recovers the related exploration and evaluation expenditure through sale. Factors that impact recoverability may include, but are not limited to, the level of resources and reserves, the cost of production, regulatory changes and commodity price movements. Acquisition expenditure is capitalised if activities in the area of interest have not yet reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves. To the extent that the capitalised acquisition expenditure is determined not to be recoverable in future, profits and net assets will be reduced in the period in which this determination is made. Further information on the carrying value of capitalised exploration and evaluation expenditure can be found in Note 13.

Other Non-financial Assets

Other non-financial assets, including property, plant and equipment and goodwill are tested for impairment annually or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Where discounted cash flows are used to assess recoverability of non-financial assets, the Group is required to use assumptions in respect of future commodity prices, foreign exchange rates, interest rates and operating costs, along with the possible impact of climate-related and other emerging business risks in determining expected future cash flows from operations. Further information on the nature and carrying value of other non-financial assets can be found in Notes 11, 12, 14 and 16.

Taxation

The Group's accounting policy for taxation requires management's judgement in relation to the types of arrangements considered to be a tax on income in contrast to an operating cost. Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Balance Sheet. Deferred tax assets, including those arising from un-recouped tax losses and capital losses, are recognised only where it is considered more likely than not they will be recovered, which is dependent on the generation of sufficient future taxable profits.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Balance Sheet and the amount of other tax losses and temporary differences not yet recognised. In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Profit or Loss and Other Comprehensive Income.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation

(i) Subsidiaries

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of Central Petroleum Limited ("the Company" or "Parent Entity") as at 30 June and the results of all subsidiaries for the year then ended. Central Petroleum Limited and its subsidiaries together are referred to in this financial report as "the Group" or "the Consolidated Entity".

Subsidiaries are all entities (including structured entities) over which the Group has control. The Group controls an entity when the Group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity.

Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated from the date that control ceases. The acquisition method is used to account for business combinations by the Group.

Intercompany transactions, balances and unrealised gains on transactions between Group entities are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of the impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Non-controlling interests (if applicable) in the results and equity of subsidiaries are shown separately in the statement of comprehensive income, statement of changes in equity and balance sheet respectively.

(ii) Joint Arrangements

The Group's investments in joint arrangements are classified as either joint operations or joint ventures; depending on the contractual rights and obligations each investor has, rather than the legal structure of the joint arrangement.

The Group's exploration and production activities are conducted through joint arrangements governed by joint operating agreements or similar contractual relationships.

A joint operation involves the joint control, and often the joint ownership, of one or more assets contributed to, or acquired for the purpose of, the joint operation and dedicated to the purposes of the joint operation. The assets are used to obtain benefits for the parties to the joint operation. Each party may take a share of the output from the assets and each bears an agreed share of expenses incurred. Each party has control over its share of future economic benefits through its share of the joint operation. The interests of the Group in joint operations are brought to account by recognising in the financial statements the Group's share of jointly controlled assets, share of expenses and liabilities incurred, and the income from the sale or use of its share of the production of the joint operation in accordance with the revenue policy in Note 1(e). Details of the joint operations are set out in Note 34.

(c) Segment Reporting

Operating segments are reported in Note 24 in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision makers, who are responsible for allocating resources and assessing performance of the operating segments, have been identified as the Executive Management Team.

(d) Foreign Currency Translation

(i) Functional and Presentation Currency

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in Australian dollars, which is Central Petroleum Limited's functional currency and presentation currency.

(ii) Transactions and Balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss, except when they are deferred in equity as qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Revenue Recognition

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

(i) Revenue from the sale of hydrocarbons

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

(ii) Farmouts and terminations

Farmouts outside the exploration phase are accounted for by derecognition of the proportion of the asset disposed of, and recognition of the consideration received or receivable from the farminee. A gain or loss is recognised for the difference between the net disposal proceeds and the carrying value of the asset disposed. Consideration is initially recognised at fair value or the cash price equivalent where payment is deferred. Interest revenue is recognised for the difference between the nominal amount of the consideration and the cash price equivalent.

Any cash consideration received directly from a farminee in respect of the farmout of an exploration asset is credited against costs previously capitalised, if applicable, with any excess accounted for as a gain on disposal.

(iii) Contract Liabilities

A contract liability is recorded for obligations under sales contracts to deliver natural gas in future periods for which payment has already been received (including “take-or-pay” arrangements). The Group applies the practical expedient in paragraph 121 of AASB 15 and does not disclose information on the transaction price allocated to performance obligations that are unsatisfied.

(iv) Interest Income

Interest income is recognised on a time proportionate basis that takes into account the effective yield on the financial assets.

(f) Government Grants

Cash grants from the government, including research and development concessions, are recognised at their fair value where there is a reasonable assurance that the grant or refund will be received, and the Group has or will comply with any conditions attaching to the grant or refund. Research and development grants are recognised as other income in the profit and loss where they relate to exploration expenditure which has been expensed in the profit and loss. Grants in the form of wages subsidies are credited against employee costs. Non-monetary grants are recognised at a nominal amount.

(g) Income Tax

Central Petroleum Limited and its wholly owned Australian controlled entities have implemented the tax consolidation legislation. The head entity is Central Petroleum Limited. As a consequence, these entities are taxed as a single entity. The Company and the other entities in the tax-consolidated group have entered into a tax funding and a tax sharing agreement.

The Group accounts for income taxes in accordance with UIG 1052 adopting the “Separate Taxpayer within Group Approach”.

The income tax expense or revenue for the period is the tax payable on the current period’s taxable income based on the applicable income tax rate adjusted by changes in deferred tax assets and liabilities attributable to temporary differences. The current income tax charge is calculated on the basis of the tax laws enacted or substantially enacted at the end of the reporting period in the countries where entities in the Group generate taxable income.

Each individual entity recognises deferred tax assets and deferred tax liabilities arising from temporary differences on the basis that the entity is subject to tax as part of the tax-consolidated group. Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses. Each entity assesses the recovery of its unused tax losses and tax credits only in the period in which they arise and before assumption by the head entity, applied in the context of the Group whether as a reduction of current tax of other entities in the group or as a deferred tax asset of the head entity. The aggregate amount of losses or credits utilised or recognised as a deferred tax asset by the head entity is apportioned on a systematic and reasonable basis.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(g) Income Tax (continued)

Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that, at the time of the transaction, affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised, or the deferred income tax liability is settled.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

(h) Leases

The Group's accounting policy for leases where the Group is lessee is described in Note 12(c).

(i) Impairment of Assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

(j) Cash and Cash Equivalents

For the purpose of presentation in the statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of 3-months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts (if applicable) are shown within borrowings in current liabilities in the balance sheet.

(k) Trade Receivables

Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The Group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

The Group considers an allowance for expected credit losses (ECLs) for all receivables. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the debtors and the economic environment. This includes, but is not limited to, financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation and delinquency in payments.

Information about the impairment of trade receivables and the Group's exposure to credit risk, foreign currency risk and interest rate risk can be found in Note 33.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) Inventories

Inventories comprise hydrocarbon stocks, drilling materials and spare parts and are valued at the lower of cost and net realisable value. Costs are assigned to individual items of inventory on a first in first out or weighted average cost basis. Cost of inventory includes the purchase price after deducting any rebates and discounts, as well as any associated freight charges.

Net realisable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

(m) Other Financial Assets

(i) Classification

The Group's financial assets consist of receivables and security deposits. These are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for those with maturities greater than 12-months after the reporting period which are classified as non-current assets. Receivables are included in trade and other receivables (Note 8) in the balance sheet. Amounts paid as performance bonds or amounts held as security for bank guarantees are classified as other financial assets (Note 15).

(ii) Measurement

At initial recognition, the Group measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss. Loans and receivables are subsequently carried at amortised cost using the effective interest method.

The Group considers an allowance for expected credit losses (ECLs) for its financial assets. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the counterparty and the economic environment.

(n) Property, Plant and Equipment – Development and Production Assets

(i) Assets in Development

The costs of oil and gas properties in the development phase are separately accounted for and include costs transferred from exploration and evaluation assets once technical feasibility and commercial viability of an area of interest are demonstrable. When production commences, the accumulated costs are transferred to producing areas of interest except for land and buildings and surface plant and equipment associated with development assets which are recorded in the land and buildings and plant and equipment categories respectively. Amortisation is not charged on costs carried forward in respect of areas of interest in the development phase until production commences.

(ii) Producing Assets

The costs of oil and gas properties in production are separately accounted for and include costs transferred from exploration and evaluation assets, transferred development assets and the ongoing costs of continuing to develop reserves for production including an estimate of the future costs to restore the site. Land and buildings and surface plant and equipment associated with producing areas of interest are recorded in the land and buildings and plant and equipment categories respectively.

Depreciation of producing assets is calculated for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method which will amortise the cost of carried forward exploration, evaluation, subsurface development expenditure (subsurface assets) and capitalised restoration costs over the life of the estimated Proven plus Probable (2P) hydrocarbon reserves for an asset or group of assets, together with estimated future costs necessary to develop the hydrocarbon reserves included in the calculation.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

All property, plant and equipment is stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Cost may also include transfers from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance costs are charged to profit or loss during the reporting period in which they are incurred.

Land is not depreciated. Depreciation of plant and equipment is calculated on a reducing balance basis so as to write off the net costs of each asset over the expected useful life. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each balance date.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. Gains and losses on disposals are determined by comparing proceeds with the carrying amount. These are included in the profit or loss.

The expected useful life for each class of depreciable assets is:

Class of Fixed Asset	Expected Useful Life
Buildings	40 years
Leasehold Improvements	2 – 6 years
Plant and Equipment	2 – 30 years
Motor Vehicles	5 – 10 years

(p) Exploration Expenditure

Exploration and evaluation costs are expensed as incurred. Acquisition costs of rights to explore are capitalised in respect of each separate area of interest and carried forward where: right of tenure of the area of interest is current; these costs are expected to be recouped through sale or successful development and exploitation of the area of interest; or where exploration and evaluation activities in the area of interest have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves. No amortisation is charged on acquisition costs capitalised under this policy.

When an area of interest is abandoned or the Directors decide that it is not commercial, any accumulated costs in respect of that area are written off in the financial period the decision is made. Each area of interest is also reviewed at the end of each accounting period and accumulated costs written off to the extent that they will not be recoverable in the future.

(q) Goodwill

Goodwill arising on the acquisition of subsidiaries is not amortised, but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate a potential impairment. Goodwill is carried at cost less accumulated impairment losses.

Goodwill is allocated to cash generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose. The units or groups of units are identified at the lowest level at which goodwill is monitored for internal management purposes, being the producing assets segments (Note 24).

(r) Trade and Other Payables

These amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which are unpaid. The amounts are unsecured and are usually paid within 30 days of recognition, except contributions to Joint Arrangements that are settled in line with the Joint Operating Agreements. Trade and other payables are presented as current liabilities unless payment is not due within 12-months from the reporting date. They are recognised initially at their fair value and subsequently measured at amortised cost using the effective interest method.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions

(i) Restoration and Rehabilitation

The Group records the present value of the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas.

A restoration provision is recognised and updated at different stages of the development and construction of a facility and then reviewed on an annual basis. When the liability is initially recorded, the present value of the estimated future cost is capitalised by increasing the carrying amount of the related property plant and equipment. Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs.

The carrying amount capitalised in property plant and equipment is depreciated over the useful life of the related producing asset (refer to Note 1(n)).

Costs incurred that relate to an existing condition caused by past operations and do not have a future economic benefit are expensed.

(ii) Onerous Contracts

An Onerous Contracts provision is recognised where the unavoidable costs of meeting obligations under the contract exceeds the value of the economic benefits expected to be received under the contract.

(iii) Other

Provisions for legal claims and make good obligations are recognised when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount has been reliably estimated. Provisions are not recognised for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of management’s best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as accretion expense within finance costs.

(t) Employee Benefits

(i) Short-term Obligations

Liabilities for wages and salaries, including non-monetary benefits, annual leave and long service leave expected to be settled within 12-months after the end of the period in which the employees render the related service are recognised in respect of employees' services up to the end of the reporting period and are measured at the amounts expected to be paid when the liabilities are settled. The liability for annual leave and long service leave is recognised in the provision for employee benefits. All other short-term employee benefit obligations are presented as payables.

(ii) Long-term Employee Benefit Obligations

The liability for long service leave which is not expected to be settled within 12-months after the end of the period in which the employees render the related service is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the end of the reporting period. Consideration is given to expected future wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted using market yields at the end of the reporting period with terms to maturity and currency that match, as closely as possible, the estimated future cash outflows.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(t) Employee Benefits (continued)

(iii) Share-based Payments

Share-based compensation benefits are provided to employees by Central Petroleum Limited.

The fair value of options or rights granted is recognised as an employee benefits expense with a corresponding increase in equity. The total amount to be expensed is determined by reference to the fair value of the rights or options granted, which includes any market performance conditions and the impact of any non-vesting conditions but excludes the impact of any service and non-market performance vesting conditions.

Non-market vesting conditions are included in assumptions about the number of rights or options that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each period, the entity revises its estimates of the number of rights or options that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in profit or loss, with a corresponding adjustment to equity.

(iv) Termination Benefits

Termination benefits are payable when employment is terminated by the Group before the normal retirement date, or when an employee accepts voluntary redundancy in exchange for these benefits.

The Group recognises termination benefits at the earlier of the following dates: (a) when the Group can no longer withdraw the offer of those benefits; and (b) when the entity recognises costs for a restructuring that is within the scope of AASB 137 and involves the payment of terminations benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer. Benefits falling due more than 12-months after the end of the reporting period are discounted to present value.

(u) Contributed Equity

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

(v) Dividends

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

(w) Earnings Per Share

(i) Basic Earnings Per Share

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

(ii) Diluted Earnings Per Share

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

(x) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense. Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the balance sheet.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 25, has been prepared on the same basis as the consolidated financial statements except for investments in subsidiaries, associates and joint venture entities which are accounted for at cost in the financial statements of Central Petroleum Limited.

(z) Business Combinations

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the:

- fair values of the assets transferred;
- liabilities incurred to the former owners of the acquired business;
- equity interests issued by the Group;
- fair value of any asset or liability resulting from a contingent consideration arrangement; and
- fair value of any pre-existing equity interest in the subsidiary.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are, with limited exceptions, measured initially at their fair values at the acquisition date. The Group recognises any non-controlling interest in the acquired entity on an acquisition-by-acquisition basis either at fair value or at the non-controlling interest's proportionate share of the acquired entity's net identifiable assets.

Acquisition related costs are expensed as incurred.

The excess of the:

- consideration transferred;
- amount of any non-controlling interest in the acquired entity; and
- acquisition-date fair value of any previous equity interest in the acquired entity

over the fair value of the net identifiable assets acquired is recorded as goodwill. If those amounts are less than the fair value of the net identifiable assets of the business acquired, the difference is recognised directly in profit or loss as a bargain purchase.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent consideration is classified either as equity or a financial liability. Amounts classified as a financial liability are subsequently remeasured to fair value with changes in fair value recognised in profit or loss.

If the business combination is achieved in stages, the acquisition date carrying value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date. Any gains or losses arising from such remeasurement are recognised in profit or loss.

(aa) Standards, Amendments and Interpretations

The Group has applied the following standards and amendments for the first time for their annual reporting period commencing 1 July 2020:

- AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material [AASB 101 and AASB 108]
- AASB 2018-6 Amendments to Australian Accounting Standards – Definition of a Business [AASB 3]
- AASB 2019-3 Amendments to Australian Accounting Standards – Interest Rate Benchmark Reform [AASB 9, AASB 139 and AASB 7]
- AASB 2019-5 Amendments to Australian Accounting Standards – Disclosure of the Effect of New IFRS Standards Not Yet issued in Australia [AASB 1054]
- Conceptual Framework for Financial Reporting and AASB 2019-1 Amendments to Australian Accounting Standards – References to the Conceptual Framework.

The amendments listed above did not have any impact on the amounts recognised in prior periods and are not expected to significantly affect the current or future periods.

The IFRS Interpretations Committee (IFRIC) issued agenda decisions relating to the accounting for SaaS arrangements. The Group has implemented this guidance and determined that there is no material impact as a result of the change in accounting policy.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

(a) Revenue from contracts with customers

	2021 $'000	2020 $'000
Sale of hydrocarbon products - point in time		
Natural gas	54,355	58,960
Crude oil and condensate	5,472	6,086
Total revenue from contracts with customers	**59,827**	**65,046**

Revenue relating to contracts with major customers is disclosed in Note 24 – Segment Reporting.

(b) Contract Liabilities

	2021 Current $'000	2021 Non-current $'000	2021 Total $'000	2020 Current $'000	2020 Non-current $'000	2020 Total $'000
Deferred Revenue – take-or-pay contracts[1]	1,357	11,017	12,374	2,714	18,977	21,691
Deferred Revenue – other gas sales contracts[2]	3,887	4,680	8,567	8,177	3,987	12,164
Total contract liabilities	**5,244**	**15,697**	**20,941**	**10,891**	**22,964**	**33,855**

1 Take-or-pay proceeds received are taken to revenue at the earlier of physical delivery of the gas to the customer, or upon forfeiture of the right to gas under the contract. No revenue has been recognised during the year for gas forfeited under take-or-pay contracts.

2 Deferred Revenue from other contracts represents gas pre-sold to customers which is yet to be delivered. Amounts are recognised as Deferred Revenue when no cash settlement option exists for the customer. Where a cash settlement option previously existed, the amount transferred to Deferred Revenue is the equivalent fair value of that cash settlement option at the time that option ceased to be available.

During the year the Group secured a new Gas Supply Agreement to supply 3.5 PJ of gas over calendar years 2022 and 2023. The sale proceeds were pre-paid in full during the year and have been included as deferred revenue. Other movements in contract liabilities during the year included $7,908,000 (2020: $7,693,000) recognised as revenue from amounts included in contract liabilities at the beginning of the year, finance charges, and new take or pay amounts accrued. Deferred revenue liabilities of $20,941,000 associated with available for sale assets as at 30 June 2021 have been reclassified as a current liability "Liabilities directly associated with assets classified as held for sale" (refer Note 10).

3. OTHER INCOME

	2021 $'000	2020 $'000
Interest	76	152
Profit on disposal of exploration permits (a)	–	8,393
Profit on disposal of inventory and other assets	79	60
Other income	—	5
Total other income	**155**	**8,610**

(a) In January 2020 the Consolidated Entity received a Sole Funding Commitment Termination Fee of $7,713,000 from its joint venture partner in ATP2031. Under the terms of the Joint Venture Agreement this amount represented the balance of consideration payable in respect of the transfer of a 50% interest in the Permit to the joint venture partner. The balance of $680,000 in the 2020 year relates to the profit recorded on disposal of interests in Northern Territory exploration permits EP93, EP97 and EP107 following government approval and registration of the transfer.

4. EXPENSES

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

	NOTE	2021 $'000	2020 $'000
Depreciation			
Buildings	11	332	350
Producing assets	11	6,942	9,945
Plant and equipment	11	4,577	5,353
Leasehold improvements	11	40	40
Right of use assets	12(b)	514	492
Total depreciation		**12,405**	**16,180**
Amortisation			
Software	14	98	77
Rental expense relating to operating leases not recognised on the Balance Sheet – Minimum lease payments	12(b)	9	39
Impairment expense	4(c)	–	177
Finance costs			
Interest and fees on debt facilities		4,074	5,191
Interest on lease liabilities	12(b)	70	102
Interest on other financial liabilities		—	56
Revaluation of financial liabilities		—	(2)
Amortisation of deferred finance costs		36	575
Accretion charges		1,491	511
Total finance costs		**5,671**	**6,433**

(b) Government Grants

In response to the impacts of COVID-19 the Australian Government made the JobKeeper support package available to eligible affected businesses. The Company recognised subsidies totalling $891,000 (2020: $759,000) against net employee costs.

In addition, $218,000 (2020: Nil) was received from the Northern Territory Government as training incentives for operational staff and recognised against net employee costs.

(c) Impairment of Exploration Assets

In the 2020 financial year the Consolidated Entity fully impaired the assets relating to exploration tenement EP105 and application area EP(A)130 amounting to $177,000. The impairment was based on the limited likelihood of future work being undertaken in those areas.

5. INCOME TAX

This note provides an analysis of the Group's income tax expense, shows what amounts are recognised directly in equity and how the tax credit is affected by non-assessable and non-deductible items. It also explains significant estimates made in relation to the Group's tax position.

(a) Income tax expense

	2021 $'000	2020 $'000
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**

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

	2021 $'000	2020 $'000
Profit before income tax expense	251	5,411
Prima facie tax expense at 30% (2020: 30%)	75	1,623
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	18	180
Share based payments	559	581
Other items	10	8
Sub-total	662	2,392
Recognition of previously unrecognised deferred tax assets	(662)	(2,392)
Income tax expense	**—**	**—**

(c) Amounts recognised directly in equity

	2021 $'000	2020 $'000
Aggregate deferred tax arising in the reporting period and not recognised in net profit or loss or other comprehensive income but directly debited or credited to equity:		
Net deferred tax – debited directly to equity	2	45
Deferred tax assets not recognised	(2)	(45)
Net amounts recognised directly in equity	**—**	**—**

(d) Tax Losses

	2021 $'000	2020 $'000
Unutilised tax losses for which no deferred tax asset has been recognised	139,107	126,635
Potential tax benefit at 30%	**41,732**	**37,991**

Unutilised tax losses are available for use in Australia and are available to offset future taxable profits of the income tax consolidated group, subject to the relevant tax loss recoupment requirements being met.

5. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2021 $'000	2020 $'000
Deferred tax assets		
Provisions and accruals	14,469	14,171
Deferred revenue	999	1,845
Other expenditure	279	425
Borrowing costs	95	56
Unutilised losses	52,695	52,267
Total deferred tax assets before set-offs	68,537	68,764
Set-off of deferred tax liabilities pursuant to set-off provisions	(10,963)	(14,276)
Net deferred tax assets not recognised	**57,574**	**54,488**
Movements in deferred tax assets		
Opening balance at 1 July	14,276	14,454
Credited/(charged) to the income statement	(3,313)	(178)
Closing balance at 30 June	**10,963**	**14,276**
Deferred tax assets to be recovered after more than 12-months	8,905	11,299
Deferred tax assets to be recovered within 12-months	2,058	2,977
	10,963	**14,276**
Deferred tax liabilities		
Accrued income	—	3
Capitalised exploration	2,516	2,503
Property, plant and equipment	8,447	11,770
Total deferred tax liabilities before set-offs	10,963	14,276
Set-off of deferred tax assets pursuant to set-off provisions	(10,963)	(14,276)
Net deferred tax liabilities	—	—
Movements in deferred tax liabilities		
Opening balance at 1 July	14,276	14,454
Charged/(credited) to the income statement	(3,313)	(178)
Closing balance at 30 June[1]	**10,963**	**14,276**
Deferred tax liabilities to be recovered after more than 12-months	10,963	14,097
Deferred tax liabilities to be recovered within 12-months	-	179
	10,963	**14,276**

1 At 30 June 2021 $4,781,000 of Deferred Tax Liabilities related to assets and liabilities classified as held for sale (2020: Nil).

6. REMUNERATION OF AUDITORS

	2021 $	2020 $
The following fees were paid or payable for services provided by PwC Australia, the auditor of the Company, its related practices and non-related audit firms:		
(i) Audit and other assurance services		
Audit and review of Group financial statements	194,538	213,265
(ii) Taxation services		
Income Tax compliance	9,129	14,657
Other tax related services	26,864	26,092
Total taxation services	35,993	40,749
Total remuneration of PwC	**230,531**	**254,014**

7. CASH AND CASH EQUIVALENTS

	2021 $000	2020 $000
Cash and cash equivalents	**37,165**	**25,918**
Made up as follows:		
Corporate cash and bank balances (a)	36,281	25,252
Joint arrangements (b)	878	666
Cash and cash equivalents per Balance Sheet	**37,159**	**25,918**
Bank balances included in assets classified as held for sale (Note 10)	6	—
Total cash and cash equivalents	**37,165**	**25,918**

(a) $11,112,000 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2020: $5,486,000), including, but not limited to operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, and debt servicing.

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

(i) Risk exposure

The Group's exposure to credit and interest rate risk is discussed in Note 33.

8. TRADE AND OTHER RECEIVABLES

	2021 $'000	2020 $'000
Current		
Trade receivables	—	476
Accrued income (a)	5,628	4,698
Other receivables	456	279
Prepayments	1,027	1,321
	7,111	**6,774**

(a) Accrued income relates to the revenue recognition of hydrocarbon volumes delivered to respective customers but not yet invoiced.

Due to the nature of the Group's receivables, their carrying values are considered to approximate their fair values. The Group applies the simplified approach to providing for expected credit losses (refer Note 33(a)).

9. INVENTORIES

	2021 $'000	2020 $'000
Crude oil and natural gas	28	61
Spare parts and consumables	1,035	1,975
Drilling materials and supplies at cost	558	545
	1,621	**2,581**

10. ASSETS AND LIABILITIES CLASSIFIED AS HELD FOR SALE

On 25 May 2021, the Group announced it had entered into a binding agreement with New Zealand Oil and Gas Limited ("NZOG") and Cue Energy Resources Limited ("Cue") to sell 50% of the Group's current working interest in its Amadeus Basin Producing Assets.

The assets being sold consist of 50% of the Group's interest in its producing assets in the Northern Territory, namely Mereenie Oil and Gas Field (OL 4/5), Palm Valley Gas Field (OL 3), and Dingo Gas Field (L7).

At 30 June 2021, the transaction was subject to various regulatory approvals. Completion is expected to occur on 1 October 2021. At 30 June 2021, assets of $57,968,000 were classified as held for sale and liabilities of $39,436,000 were associated with these assets. The major classes of assets comprising the sale interests classified as held for sale and associated liabilities are as follows:

	2021 $'000
Assets classified as held for sale	
Cash	6
Receivables	175
Inventories	1,053
Property plant and equipment	54,294
Right of use assets	145
Intangibles	17
Exploration assets	325
Goodwill	1,953
Total assets classified as **held for sale**	**57,968**

	2021 $'000
Liabilities directly associated with assets classified as held for sale	
Trade and other payables	1,596
Current deferred revenue	5,244
Current lease liabilities	26
Non-current deferred revenue	15,697
Non-current lease liabilities	124
Non-current provisions	16,749
Total liabilities directly associated with assets classified as held for sale	**39,436**

11. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2020				
Opening net book amount	2,529	81,046	39,900	123,475
Additions	—	264	2,593	2,857
Changes to rehabilitation estimates	—	(2,769)	(5)	(2,774)
Disposals and write offs	—	—	(25)	(25)
Depreciation charge	(350)	(9,945)	(5,393)	(15,688)
Closing net book amount	**2,179**	**68,596**	**37,070**	**107,845**
At 30 June 2020				
Cost	3,869	98,384	67,800	170,053
Accumulated depreciation	(1,690)	(29,788)	(30,730)	(62,208)
Net book amount	**2,179**	**68,596**	**37,070**	**107,845**
Year ended 30 June 2021				
Opening net book amount	2,179	68,596	37,070	107,845
Additions	—	5,937	5,855	11,792
Changes to rehabilitation estimates	—	536	4	540
Disposals and write offs	—	—	(4)	(4)
Depreciation charge	(332)	(6,942)	(4,617)	(11,891)
Reclassified as held for sale	(917)	(34,254)	(19,123)	(54,294)
Closing net book amount	**930**	**33,873**	**19,185**	**53,988**
At 30 June 2021				
Cost	1,952	53,381	40,211	95,544
Accumulated depreciation	(1,022)	(19,508)	(21,026)	(41,556)
Net book amount	**930**	**33,873**	**19,185**	**53,988**

At 30 June 2021, $3,015,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2020: $1,908,000).

12. LEASES

(a) Amounts recognised in the balance sheet

The balance sheet shows the following amounts relating to leases:

	2021 $'000	2020 $'000
Right-of-use assets		
Land & Buildings	1,211	673
Plant & Equipment	244	386
	1,455	**1,059**
Lease Liabilities		
Current	517	608
Non-current	992	618
	1,509	**1,226**

12. LEASES (CONTINUED)

(a) Amounts recognised in the balance sheet (continued)

Additions to the right-of-use assets during the 2021 financial year were $1,055,000 (2020: $159,000) and $145,000 was reclassified as held for sale – refer Note 10 (2020: Nil).

(b) Amounts recognised in the statement of profit or loss

The statement of profit or loss shows the following amounts relating to leases:

	2021 $'000	2020 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	359	359
Plant & Equipment	155	133
Total depreciation of right-of-use assets	**514**	**492**
Interest expense	70	102
Expense related to short term leases included in cost of sales and general and administrative expenses	9	39

The total cash outflow for leases in 2021 was $691,000 (2020: $650,0000).

(c) The Group's leasing activities and how they are accounted for

The Group leases office space, property easements, equipment and vehicles. Rental contracts are typically made for fixed periods of 3 to 8 years but may have extension options as described below. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose any covenants other than the security interests in the leased assets that are held by the lessor. Leased assets may not be used as security for borrowing purposes.

Contracts may contain both lease and non-lease components. The Group has elected not to separate lease and non-lease components and instead accounts for these as a single lease component.

Leases are recognised as a right-of-use asset and a corresponding liability at the date at which the leased asset is available for use by the Group. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- fixed payments (including in-substance fixed payments), less any lease incentives receivable;
- variable lease payment that are based on an index or a rate;
- amounts expected to be payable by the lessee under residual value guarantees;
- the exercise price of a purchase option if the lessee is reasonably certain to exercise that option; and
- payments of penalties for terminating the lease, if the lease term reflects the lessee exercising that option.

Extension and termination options are included in some leases across the Group. These are used to maximise operational flexibility in terms of managing the assets used in the Group's operations. The extension and termination options held are exercisable only by the Group and not by the respective lessor. Lease payments to be made under reasonably certain extension options are also included in the measurement of the liability.

The lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be determined, the lessee's incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms, security and conditions.

12. LEASES (CONTINUED)

(c) The Group's leasing activities and how they are accounted for (continued)

To determine the incremental borrowing rate, the Group:

- where possible, uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received;
- uses a build-up approach that starts with a risk-free interest rate adjusted for credit risk for leases held by Central Petroleum Limited, which does not have recent third-party financing; and
- makes adjustments specific to the lease, e.g. term, country, currency and security.

The Group is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use asset.

Right-of-use assets are measured at cost comprising the following:

- the amount of the initial measurement of lease liability;
- any lease payments made at or before the commencement date less any lease incentives received;
- any initial direct costs; and
- the present value of estimated future restoration costs.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Group is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Payments associated with short-term leases and leases of low-value assets are recognised on a straight-line basis as an expense in profit or loss. Short-term leases are leases with a lease term of 12 months or less.

If there is a modification to a lease arrangement, a determination of whether the modification results in a separate lease arrangement being recognised needs to be made. Where the modification does result in a separate lease arrangement needing to be recognised, due to an increase in scope of a lease through additional underlying leased assets and a commensurate increase in lease payments, the measurement requirements as described above need to be applied.

Where the modification does not result in a separate lease arrangement, from the effective date of the modification, the Group will remeasure the lease liability using the redetermined lease term, lease payments and applicable discount rate. A corresponding adjustment will be made to the carrying amount of the associated right-of-use asset. Additionally, where there has been a partial or full termination of a lease, the Group will recognise any resulting gain or loss in the income statement.

13. EXPLORATION ASSETS

	2021 $'000	2020 $'000
Acquisition costs of right to explore	**8,397**	**8,722**
Movement for the year:		
Balance at the beginning of the year	8,722	8,899
Impairment expense (Note 4(c))	–	(177)
Reclassified as held for sale (Note 10)	(325)	—
Balance at the end of the year	**8,397**	**8,722**

14. INTANGIBLE ASSETS

	2021 $'000	2020 $'000
Software		
At the beginning of the year		
Cost	788	512
Accumulated amortisation	(476)	(399)
Net book value	**312**	**113**
Movements for the year		
Opening net book amount	312	113
Additions	105	276
Amortisation	(98)	(77)
Reclassified as held for sale	(17)	—
Closing net book amount	**302**	**312**
At the end of the year		
Cost	848	788
Accumulated amortisation	(546)	(476)
Net book value	**302**	**312**

15. OTHER FINANCIAL ASSETS

	2021 $'000	2020 $'000
Non-Current		
Security bonds on exploration permits and rental properties	**4,218**	**2,656**

Security bonds are provided to State or Territory governments in respect of certain performance obligations arising from awarded petroleum and mineral tenements. The bonds are typically provided as cash or as bank guarantees in favour of the State or Territory government secured by term deposits with the financial institution providing the bank guarantee.

16. GOODWILL

	2021 $'000	2020 $'000
Goodwill arising from business combinations	**1,953**	**3,906**

Movement

As 30 June 2021 $1,953,000 of goodwill was reclassified as held for sale (refer Note 10).

Impairment tests for goodwill

Goodwill is monitored by management at the level of the operating segments and has been allocated to the gas producing assets cash generating unit. There has been no impairment of amounts previously recognised as goodwill. Goodwill is tested for impairment where an indicator of impairment exists, and at least on an annual basis.

On 25 May 2021 the Group entered into a binding agreement with New Zealand Oil & Gas Limited (NZOG) and Cue Energy Resources Limited (Cue) to sell 50% of the Group's current equity interests in its Amadeus Basin producing assets. The assets being disposed represent 50% of the total cash generating unit upon which Central assesses recoverable amount each year.

Central will receive an upfront cash payment of $29,000,000 and deferred consideration of $40,000,000 to fund Central's share of selected near-term development, appraisal and exploration activities in the producing areas. In addition, NZOG and Cue will assume 50% of Central's relevant liabilities relating to gas which has previously been paid for but not delivered under pre-sale or take-or-pay arrangements with a book value of $20,941,000 at 30 June 2021.

Management and the Board have concluded that this transaction provides evidence of the fair value of the underlying assets, net of liabilities, being disposed and will therefore adopt the fair value less costs of disposal measurement methodology as at 30 June 2021.

16. GOODWILL (CONTINUED)

Fair Value Measurement is governed by AASB 13 which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It assumes the asset or liability is exchanged in an orderly transaction between market participants at the measurement date under current market conditions.

Management and the Board believe the sale process meets the requirements of an orderly transaction where all parties were acting in their own economic best interests and therefore can be relied upon as evidence of the fair value of the assets being disposed net of the liabilities being transferred.

The value of the transaction consideration (grossed up for the value of liabilities assumed by the purchaser) substantially exceeds the carrying value of the assets being sold and associated goodwill. On this basis Management and the Board have concluded there is no impairment of the carrying value of Goodwill or other producing assets at 30 June 2021.

17. TRADE AND OTHER PAYABLES

	2021 $'000	2020 $'000
Current		
Trade payables	5,312	2,026
Other payables	31	11
Accruals	5,148	3,250
	10,491	**5,287**

Trade payables are usually non-interest bearing provided payment is made within the terms of credit. The Consolidated Entity's exposure to liquidity and currency risks related to trade and other payables is disclosed in Note 33.

18. BORROWINGS

		2021 $'000	2020 $'000
(a)	Current[1]		
	Debt facilities	36,000	6,964
(b)	Non-current[1]		
	Debt facilities	30,809	63,809

Details regarding interest bearing liabilities are contained in Note 33(e).

19. PROVISIONS

	2021			2020		
	Current $'000	**Non-Current $'000**	**Total $'000**	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	3,184	1,084	4,268	3,942	828	4,770
Restoration and rehabilitation (b)	—	23,466	23,466	120	37,988	38,108
Joint Venture production over-lift (c)	734	2,829	3,563	712	3,460	4,172
	3,918	**27,379**	**31,297**	**4,774**	**42,276**	**47,050**

(a) The current provision for employee entitlements includes accrued short term incentive plans, severance entitlements, accrued annual leave and the unconditional entitlements to long service leave where employees have completed the required period of service. The amounts are presented as current, since the Consolidated Entity does not have an unconditional right to defer settlement for these obligations. However, based on past experience, the Group does not expect all employees to take the full amount of accrued leave or require payment in the next 12-months. Current leave obligations that are not expected to be taken or paid within the next 12-months amount to $635,000 (2020: $788,000).

(b) Provisions for future removal and restoration costs are recognised where there is a present obligation and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

(c) Under an Interim Gas Balancing Agreement with its joint venture partners, the Group has taken a higher proportion of natural gas produced from the Mereenie joint venture than its joint venture percentage entitlement. A provision has been recognised to reflect the expected additional production costs of rebalancing production entitlements between the joint venture partners from future operations.

19. PROVISIONS (CONTINUED)

Movements in Provisions

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

2021	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Total $'000
Carrying amount at start of year	4,770	38,108	4,172	47,050
Change in provision charged to property, plant and equipment	—	540	—	540
Additional provisions charged to profit or loss	2,404	1,371	123	3,898
Unwinding of discount	—	314	—	314
Amounts used during the year	(2,906)	(118)	(732)	(3,756)
Reclassified as held for sale (Note 10)	—	(16,749)	—	(16,749)
Carrying amount at end of year	**4,268**	**23,466**	**3,563**	**31,297**

20. CONTRIBUTED EQUITY

(a) Share capital

	2021 $'000	2020 $'000
724,093,661 fully paid ordinary shares (2020: 723,288,869)	**197,776**	**197,776**

Ordinary shares have no par value and the Company does not have a limited amount of authorised capital.

On a show of hands, every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote.

Movements in ordinary share capital

	2021 Number of Shares	2020 Number of Shares	2021 $'000	2020 $'000
Balance at start of year	723,288,869	713,355,716	197,776	197,776
Shares issued under Employee Incentive Plans	804,792	9,933,153	—	—
Balance at end of year	**724,093,661**	**723,288,869**	**197,776**	**197,776**

(b) Share Options

The following table shows the movement in options over ordinary shares during the year:

Class	Expiry Date	Exercise Price	Balance at Start of Year	Issued During the Year	Lapsed During the Year	Exercised During the Year	Balance at the End of the Year
Executive Share Option Plan	30 Jun 2023	$0.200	18,151,116	—	—	—	18,151,116
Total			**18,151,116**	**—**	**—**	**—**	**18,151,116**

(c) Share rights under the Long Term Incentive Plan

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

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

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each eligible employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price at the start of the plan year. The table below sets out the maximum number of share rights subject to performance hurdles outstanding at year end and movements for the year.

20. CONTRIBUTED EQUITY (CONTINUED)

Class	Expiry Date	Plan Year Commencing	Balance at Start of Year	Issued During the Year	Cancelled or Lapsed During the Year	Exercised During the Year	Balance at the End of the Year
Employee LTIP rights	05 Jan 2021	1 Jul 2015	7,305	—	—	(7,305)	—
Employee LTIP rights	08 Dec 2022	1 Jul 2016	579,386	—	—	(579,386)	—
Employee LTIP rights	03 Oct 2022	1 Jul 2017	4,601,645	20,271	(4,390,117)	(218,101)	13,698
Employee LTIP rights	23 May 2023	1 Jul 2017	16,868	—	(16,868)	—	—
Employee LTIP rights	28 Jun 2023	1 Jul 2017	135,920	—	(135,920)	—	—
Employee LTIP rights	22 May 2024	1 Jul 2018	6,444,398	—	(187,418)	—	6,256,980
Employee LTIP rights	12 Nov 2024	1 Jul 2018	1,837,109	—	—	—	1,837,109
Employee LTIP rights	30 Jun 2024	1 Jul 2019	7,353,175	30,545	(561,314)	—	6,822,406
Employee Deferred Share rights[1]	30 Jun 2025	1 Jul 2019	—	3,692,054	—	—	3,692,054
Employee LTIP rights	30 Jun 2025	1 Jul 2020	—	9,917,120	—	—	9,917,120
Total			**20,975,806**	**13,659,990**	**(5,291,637)**	**(804,792)**	**28,539,367**

[1] In respect of year ended 30 June 2020, certain employees were awarded deferred share rights rather than cash short term incentives. These deferred share rights have a vesting date of 30 June 2023.

The rights do not entitle the holders to participate in any share issue of the Company or any other entity.

(d) Capital risk management

The Group's objective when managing capital is to safeguard the ability to continue as a going concern to ultimately add value for shareholders through the exploitation and production of hydrocarbon resources. This is monitored through the use of cash flow forecasts. In order to satisfy the capital requirements of the Group, the Company may issue new shares or other equity instruments.

21. RESERVES

	2021 $'000	2020 $'000
Share options reserve	**29,094**	**27,238**
Movements:		
Balance at start of year	27,238	25,310
Share based payment costs (a)	1,862	1,937
Transaction costs	(6)	(9)
Balance at end of year	**29,094**	**27,238**

(a) Share based payments are provided to employees under the Employee Rights Plan and Executive Share Option Plan. Refer to Note 32 for further details of share-based payments.

22. ACCUMULATED LOSSES

	2021 $'000	2020 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year	(223,432)	(228,843)
Net profit for the year	251	5,411
Balance at end of year	**(223,181)**	**(223,432)**

23. EARNINGS/(LOSS) PER SHARE

		2021	2020
(a)	**Basic earnings per share (cents)**	**0.03**	**0.75**
(b)	**Diluted earnings per share (cents)**	**0.03**	**0.75**
(c)	**Profit used in earnings per share calculation**		
	Profit attributed to ordinary equity holders ($'000)	**251**	**5,411**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic earnings per share	**723,619,673**	**720,898,329**
	Adjustments for the calculation of diluted earnings per share:		
	Employee share rights	17,469,319	1,057,114
	Weighted average number of shares used as the denominator in calculating diluted earnings per share	**741,088,992**	**721,955,443**

Options and Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic earnings per share.

24. SEGMENT REPORTING

The Group has identified its operating segments based on the internal reports that are reviewed and used by the executive management team (the chief operating decision makers) in assessing performance and in determining the allocation of resources. The following operating segments are identified by management based on the nature of the business or venture.

(a) Producing assets

Production and sale of crude oil, natural gas and associated petroleum products from fields that are in the production phase.

(b) Development assets

Fields under development in preparation for the sale of petroleum products. There were no fields under development during the current or prior financial year.

(c) Exploration assets

Exploration and evaluation of permit areas.

(d) Unallocated items

Unallocated items comprise non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

(e) Performance monitoring and evaluation

Management monitors the operating results of the operating segments separately for the purpose of making decisions about resource allocation and performance assessment.

The Consolidated Entity's operations are wholly in one geographical location, being Australia.

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2021	Producing Assets 2021 $'000	Exploration Assets 2021 $'000	Unallocated Items 2021 $'000	Consolidation 2021 $'000
Revenue from contracts with customers				
Natural gas	54,355	—	—	54,355
Crude oil and condensate	5,472	—	—	5,472
Total revenue from contracts with customers	**59,827**	**—**	**—**	**59,827**
Cost of sales	(28,852)	—	—	(28,852)
Gross profit	**30,975**	**—**	**—**	**30,975**
Other income	7	70	2	79
Share based employee benefits[1]	—	—	(1,862)	(1,862)
General and administrative expenses	—	—	(924)	(924)
Employee benefits and associated costs	—	—	(2,180)	(2,180)
EBITDAX[2]	**30,982**	**70**	**(4,964)**	**26,088**
Depreciation and amortisation[1]	(11,783)	—	(720)	(12,503)
Exploration expenditure	(1,012)	(6,727)	—	(7,739)
Interest revenue	21	—	55	76
Finance costs	(5,286)	(12)	(373)	(5,671)
Profit / (loss) before income tax	**12,922**	**(6,669)**	**(6,002)**	**251**
Taxes	—	—	—	—
Profit / (loss) for the year	**12,922**	**(6,669)**	**(6,002)**	**251**
Segment assets	**133,492**	**10,264**	**30,416**	**174,172**
Segment liabilities	**(150,774)**	**(5,462)**	**(14,247)**	**(170,483)**
Capital expenditure				
Property, plant and equipment	11,703	—	89	11,792
Intangibles	5	—	99	104
Total capital expenditure	**11,708**	**—**	**188**	**11,896**

1 Non-cash item.

2 EBITDAX is earnings before interest, taxation, depreciation, amortisation, and exploration expense.

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2020	Producing Assets 2020 $'000	Exploration Assets 2020 $'000	Unallocated Items 2020 $'000	Consolidation 2020 $'000
Revenue from contracts with customers				
Natural gas	58,960	—	—	58,960
Crude oil and condensate	6,086	—	—	6,086
Total revenue from contracts with customers	**65,046**	**—**	**—**	**65,046**
Cost of sales	(33,386)	—	—	(33,386)
Gross profit	**31,660**	**—**	**—**	**31,660**
Other income	9	8,437	12	8,458
Share based employee benefits[1]	—	—	(1,937)	(1,937)
General and administrative expenses	—	—	(266)	(266)
Employee benefits and associated costs	—	—	(4,512)	(4,512)
EBITDAX[2]	**31,669**	**8,437**	**(6,703)**	**33,403**
Depreciation and amortisation[1]	(15,528)	—	(729)	(16,257)
Exploration expenditure	(678)	(4,599)	—	(5,277)
Interest revenue	47	–	105	152
Finance costs	(5,860)	(18)	(555)	(6,433)
Impairment expense[1]	—	(177)	—	(177)
Profit / (loss) before income tax	**9,650**	**3,643**	**(7,882)**	**5,411**
Taxes	—	—	—	—
Profit / (loss) for the year	**9,650**	**3,643**	**(7,882)**	**5,411**
Segment assets	**132,817**	**10,958**	**15,998**	**159,773**
Segment liabilities	**(141,530)**	**(3,301)**	**(13,360)**	**(158,191)**
Capital expenditure				
Property, plant and equipment	2,763	—	94	2,857
Intangibles	23	—	253	276
Total capital expenditure	**2,786**	**—**	**347**	**3,133**

	2021 $'000	2020 $'000
Revenue from external customers by geographical location of production:		
Australia	**59,827**	**65,046**
Non-current assets by geographical location:		
Australia	**70,313**	**124,500**

1 Non-cash item.
2 EBITDAX is earnings before interest, taxation, depreciation, amortisation, and exploration expense.

24. SEGMENT REPORTING (CONTINUED)

(f) Major Customers

Customers with revenue exceeding 10% of the Group's total hydrocarbon sales revenue are shown below. Revenues from these customers are reported in the Producing Assets segment.

	2021 $'000	% of Sales Revenue	2020 $'000	% of Sales Revenue
Largest customer	20,028	33%	18,918	29%
Second largest customer	14,597	24%	12,712	20%
Third largest customer	10,468	17%	9,629	15%
Fourth largest customer	7,803	13%	8,504	13%
Fifth largest customer	—	—	7,649	12%

25. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2021 $'000	2020 $'000
Balance Sheet		
Current assets	29,855	21,983
Non-current assets	20,938	23,797
Total assets	50,793	45,780
Current liabilities	(28,003)	(21,749)
Non-current liabilities	(1,922)	(1,372)
Total liabilities	(29,925)	(23,121)
Net assets	**20,868**	**22,659**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	29,094	27,238
Accumulated losses	(206,002)	(202,355)
Total equity	**20,868**	**22,659**
(Loss)/Profit for the year	**(3,647)**	**10,829**
Total comprehensive (loss)/profit	**(3,647)**	**10,829**

(b) Guarantees entered into by the Parent Entity

Guarantees have been provided by the Parent Entity to subsidiaries arising out of the course of ordinary operations.

A loan facility exists under which the Parent Entity and non-borrowing subsidiaries have provided guarantees to a financier in relation to the repayment of monies owing and other performance related obligations of the Borrower typical for a borrowing of this nature. Monies received through the operation of the Palm Valley, Dingo and Mereenie fields are subject to a proceeds account and can be distributed to the Parent Entity as available when no default exists. Revenues resulting from operations outside of these assets (such as the Surprise field) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

(c) Commitments of the Parent Entity

Operating lease commitments of the Parent Entity are set out in Note 31(c).

26. RELATED PARTY TRANSACTIONS

(a) Parent Entity

The Parent Entity is Central Petroleum Limited.

(b) Subsidiaries

The consolidated financial statements include the financial statements of Central Petroleum Limited and the subsidiaries listed in the following table:

Name of Entity	Place of Incorporation	Class of Shares	Equity Holding 2021 %	Equity Holding 2020 %
Merlin Energy Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Projects Pty Ltd	Western Australia	Ordinary	100	100
Helium Australia Pty Ltd	Victoria	Ordinary	100	100
Ordiv Petroleum Pty Ltd	Western Australia	Ordinary	100	100
Frontier Oil & Gas Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Eastern Pty Ltd	Western Australia	Ordinary	100	100
Central Geothermal Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Services Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum PVD Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum (NT) Pty Ltd	Queensland	Ordinary	100	100
Jarl Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Unit Trust	N/A	Units	100	100
Central Petroleum WS (NO 1) Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum WS (NO 2) Pty Ltd	Queensland	Ordinary	100	100

(c) Key management personnel compensation

	2021 $	2020 $
Short-term employee benefits	3,265,233	3,040,943
Post-employment benefits	172,676	166,369
Long-term benefits	43,447	40,105
Share based payments	1,112,075	846,280
	4,593,431	**4,093,697**

Detailed remuneration disclosures are provided in the remuneration report on pages 35 to 49.

27. DEED OF CROSS GUARANTEE

Central Petroleum Limited and its wholly owned subsidiary companies are parties to a deed of cross guarantee under which each company guarantees the debts of the others. By entering into the deed, the wholly-owned entities have been relieved from the requirement to prepare a financial report and Directors' Report under *ASIC Corporations (Wholly-owned Companies) Instrument 2016/785*.

The parties to the deed of cross guarantee are:

- Central Petroleum Limited
- Central Petroleum Projects Pty Ltd
- Ordiv Petroleum Pty Ltd
- Central Petroleum Eastern Pty Ltd
- Central Petroleum Services Pty Ltd
- Central Petroleum (NT) Pty Ltd
- Central Petroleum Mereenie Pty Ltd
- Central Petroleum WS (NO 2) Pty Ltd
- Merlin Energy Pty Ltd
- Helium Australia Pty Ltd
- Frontier Oil & Gas Pty Ltd
- Central Geothermal Pty Ltd
- Central Petroleum PVD Pty Ltd
- Jarl Pty Ltd
- Central Petroleum WS (NO 1) Pty Ltd

The above companies represent a 'closed group' for the purposes of the instrument, and as there are no other parties to the deed of cross guarantee that are controlled by Central Petroleum Limited, they also represent the 'extended closed group'.

(a) Consolidated statement of profit or loss, statement of comprehensive income and summary of movements in consolidated retained earnings

Set out below is a consolidated statement of profit or loss, a consolidated statement of comprehensive income and a summary of movements in consolidated retained earnings of the closed group for the year ended 30 June 2021.

	2021 $'000	2020 $'000
Revenue from the sale of goods	24,984	26,505
Cost of sales	(10,342)	(11,389)
Gross profit	14,642	15,116
Other income	144	8,604
Share based employment benefits	(1,862)	(1,937)
General and administrative expenses	(912)	413
Depreciation and amortisation	(6,534)	(8,441)
Employee benefits and associated costs	(1,470)	(4,512)
Exploration expenditure	(7,736)	(5,234)
Finance costs	(2,871)	(4,367)
Impairment expense	—	(177)
Loss before income tax	(6,599)	(535)
Income tax credit	2,547	1,570
(Loss)/Profit for the year	(4,052)	1,035
Other comprehensive (loss)/profit for the year, net of tax	—	—
Total comprehensive (loss)/profit for the year	**(4,052)**	**1,035**
Accumulated losses at the beginning of the financial year	(213,992)	(214,888)
AASB 16 Lease accounting adjustments	—	(139)
(Loss)/Profit for the year	(4,052)	1,035
Accumulated losses at the end of the financial year	**(218,044)**	**(213,992)**

27. DEED OF CROSS GUARANTEE (CONTINUED)

(b) Consolidated balance sheet

Set out below is a consolidated balance sheet of the closed group as at 30 June.

	2021 $'000	2020 $'000
ASSETS		
Current assets		
Cash and cash equivalents	37,153	25,652
Trade and other receivables	3,495	3,941
Inventories	899	1,172
Assets classified as held for sale	28,519	—
Total current assets	70,066	30,765
Non-current assets		
Property, plant and equipment	25,733	55,797
Right of use assets	1,366	833
Exploration assets	8,397	8,722
Intangible assets	295	286
Other financial assets	2,645	2,110
Deferred Tax Assets	6,291	5,456
Goodwill	1,953	3,906
Total non-current assets	46,680	77,110
Total assets	**116,746**	**107,875**
LIABILITIES		
Current liabilities		
Trade and other payables	22,115	13,800
Deferred revenue	992	1,983
Borrowings	16,034	3,846
Lease liabilities	492	562
Provisions	3,184	4,062
Liabilities directly associated with assets classified as held for sale	18,399	—
Total current liabilities	61,216	24,253
Non-current liabilities		
Deferred revenue	10,797	18,537
Borrowings	21,019	35,389
Lease liabilities	922	431
Provisions	13,966	18,243
Total non-current liabilities	46,704	72,600
Total liabilities	**107,920**	**96,853**
Net assets	**8,826**	**11,022**
EQUITY		
Contributed equity	197,776	197,776
Reserves	29,094	27,238
Accumulated losses	(218,044)	(213,992)
Total equity	**8,826**	**11,022**

28. RECONCILIATION OF PROFIT AFTER INCOME TAX TO NET CASH FLOWS FROM OPERATING ACTIVITIES

	2021 $'000	2020 $'000
Profit after income tax	**251**	**5,411**
Adjustments for:		
Depreciation and amortisation	12,503	16,257
Impairment expense	—	177
Profit on disposal of assets	(6)	(51)
Profit on disposal of exploration permits	—	(8,393)
Share-based payments	1,862	1,937
Financing costs and interest (non-cash)	1,747	834
Changes in assets and liabilities relating to operating activities:		
(Increase)/Decrease in trade and other receivables	(515)	2,290
(Increase)/Decrease in inventories	(93)	138
Increase/(Decrease) in trade and other payables	1,395	(481)
Increase/(Decrease) in deferred revenue	6,850	(4,275)
Increase in provisions	142	1,883
Net cash inflow from operations	**24,136**	**15,727**

29. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

In 2020, non-cash interest relating to Other Financial Liabilities amounted to $56,000 and non-cash revaluation credits amounted to $2,000. Refer Note 4(a).

During the 2020 year an amount of $15,819,000 was transferred to Deferred Revenue from Other Financial Liabilities. This was due to a novation of rights and obligations under the MBL Gas Sale and Prepayment Agreement from MBL to a third party in respect of the Second and Third Contract Years, reflecting the removal of the cash settlement option.

Non-cash investing and financing activities disclosed in other notes are:

- Acquisition of right of use assets – Note 12(a); and
- Options and rights issued to employees under short and long term incentive plans – Note 32.

(b) Net debt reconciliation

This section provides an analysis of those liabilities for which cash flows have been or will be classified as financing activities in the statement of cash flows. Cash balances included as current assets on the balance sheet are included as the Group considers these to form part of its net debt.

Net debt

	2021 $'000	2020 $'000
Cash and cash equivalents (including cash classified as held for sale)	37,165	25,918
Borrowings and leases – repayable within one year[1]	(36,543)	(7,572)
Borrowings and leases – repayable after one year[1]	(31,925)	(64,427)
Net debt	**(31,303)**	**(46,081)**
Cash	37,165	25,918
Gross Debt – fixed interest rates	(1,659)	(1,226)
Gross debt – variable interest rates	(66,809)	(70,773)
Net debt	**(31,303)**	**(46,081)**

[1] Including leases associated with assets classified as held for sale

29. CASH FLOW INFORMATION (CONTINUED)

(b) Net debt reconciliation (continued)

Movement in Net Debt

	Other Assets	Liabilities from Financing Activities		
	Cash $'000	Borrowings $'000	Leases $'000	Total $'000
Net debt 1 July 2019	**17,806**	**(81,730)**	**(1,615)**	**(65,539)**
Cash flows	8,112	11,501	548	20,161
Acquisition - leases	—	—	(159)	(159)
Other non-cash movements	—	(544)	—	(544)
Net debt 30 June 2020	**25,918**	**(70,773)**	**(1,226)**	**(46,081)**
Cash flows	11,247	4,000	622	15,869
Acquisition - leases	—	—	(1,055)	(1,055)
Other non-cash movements	—	(36)	—	(36)
Net debt 30 June 2021	**37,165**	**(66,809)**	**(1,659)**	**(31,303)**

30. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2021 in respect of certain joint arrangement payments. As partial consideration under the terms of the purchase agreement for EP105, there is a requirement to pay the vendor the sum of $1,000,000 (2020: $1,000,000) within 12-months following the commencement of any future commercial production from the permits. No commercial production is currently forecast from these permits.

(ii) Palm Valley Gas Field Gas Price Bonus

Under the Share Sale and Purchase Deed entered into with Magellan Petroleum Australia Pty Limited (Magellan) in February 2014 for the purchase of Palm Valley and Dingo gas fields and related assets, Central Petroleum Limited is obligated to pay to Magellan a Gas Price Bonus where the weighted average price of gas sold from the Palm Valley gas field during a Contract Year exceeds certain price hurdles during a period of 15-years following Completion of the Agreement.

The Gas Price Bonus Amount is calculated as 25% of the difference between the weighted average price of gas actually sold (excluding GST and other costs) in a Contract Year and the gas price bonus hurdle applicable to that Contract Year (after adjusting for CPI), multiplied by the actual volume of gas originating and sold from the Palm Valley gas field. The weighted average price of gas sold from the Palm Valley gas field is currently below the Gas Price Bonus hurdle price and therefore no gas price bonus is payable at this time. Based on current reserves and production profiles for the Palm Valley Gas Field, and current Northern Territory gas market conditions, it is not anticipated that a gas price bonus will be payable over the relevant term and have therefore ascribed a $nil value to this contingent liability. Should access to additional reserves and significantly higher priced markets eventuate, this contingent liability will be reviewed. Importantly, any future payment of the Gas Price Bonus would only occur where sales and revenues from the Palm Valley gas field materially exceed Central's acquisition assumptions.

31. COMMITMENTS

(a) Capital commitments

The Consolidated Entity has the following capital expenditure commitments:

	2021 $'000	2020 $'000
The following amounts are due:		
Within one year	3,159	475
	3,159	**475**

(b) Exploration commitments

The Consolidated Entity has the following minimum exploration expenditure commitments:

	2021 $'000	2020 $'000
The following amounts are due:		
Within one year	11,742	10,578
Later than one year but not later than three years	56,400	55,087
Later than three years but not later than five years	—	8,100
	68,142	**73,765**

These commitments may be varied in the future as a result of renegotiations of the terms of exploration permits. In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties or relinquish (whole or part of the permit) and, as a result, obligations may be reduced or extinguished.

(c) Operating lease commitments

The Consolidated Entity has non-cancellable operating leases.

Commitments for minimum lease payments in relation to non-cancellable operating leases not recognised as a lease liability on the balance sheet are as follows:

	2021 $'000	2020 $'000
Within one year	—	10
	—	**10**

32. SHARE BASED PAYMENTS

(a) Employee options

An Executive Share Option Plan operates to provide incentives for key executives. Participation in the plan is at the Board's discretion. Details of options issued under the plan are shown below.

Grant Date	Expiry Date	Balance at Start of Year	Granted During the Year	Exercise Price	Average Fair Value Per Option	Cancelled or Expired During the Year	Balance at End of Year	Vested and Exercisable
2021								
20 Aug 2019	30 Jun 2023	13,046,116	—	$0.20	$0.120	—	13,046,116	—
07 Nov 2019	30 Jun 2023	5,105,000	—	$0.20	$0.087	—	5,105,000	—
Totals		**18,151,116**	**—**		**$0.111**	**—**	**18,151,116**	**—**
Weighted average exercise price		**$0.20**	**—**			**—**	**$0.20**	**—**
2020								
20 Aug 2019	30 Jun 2023[1]	—	13,046,116	$0.20	$0.120	—	13,046,116	—
07 Nov 2019	30 Jun 2023	—	5,105,000	$0.20	$0.087	—	5,105,000	—
Totals		**—**	**18,151,116**		**$0.111**	**—**	**18,151,116**	**—**
Weighted average exercise price		**—**	**$0.20**			**—**	**$0.20**	**—**

1 On 7 November 2019 the expiry date of these options was changed from 30 June 2032 to 30 June 2023. The modification resulted in a lower fair value than the original valuation. Under the requirements of AASB 2 the effect of any decrease in fair value is not recognised.

The weighted average remaining contractual life at 30 June 2021 was 2-years (2020:3-years). The values of Executive Options are calculated at the date of grant using a Black Scholes valuation. The following factors and assumptions were used in determining the fair value of options granted to executives during the 2020 year:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
2020							
20 Aug 2019	30 Jun 2023	$0.120	$0.20	$0.16	78%	0.92%	—
07 Nov 2019	30 Jun 2023	$0.087	$0.20	$0.17	78%	0.85%	—

(b) Rights to shares — Short Term Incentive Plan

Under the Group's Short Term Incentive Plan, the Board may issue share rights in lieu of cash payments. The following rights were issued during the year:

Grant Date	Plan Year End	Balance at Start of Year	Number of Rights Granted	Average Fair Value Per Right	Exercised During the Year	Cancelled or Forfeited	Balance at End of Year
2021							
11 Nov 2020	30 Jun2020[1]	—	3,692,054	$0.130	—	—	3,692,054
2020							
09 Aug 2019	30 Jun 2019[2]	—	3,311,771	$0.155	(3,311,771)	—	—

The weighted average fair value of share rights issued under the Short Term Incentive Plan during the year was $0.130 (2020: $0.142).

1 Share rights in respect of the performance period ended 30 June 2020 have a deferred vesting date of 30 June 2023.
2 Share rights in respect of the performance period ended 30 June 2019 vested immediately on issue.

32. SHARE BASED PAYMENTS (CONTINUED)

(c) Rights to shares — Long Term Incentive Plan

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

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

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

Share based payment expense for the year includes amounts expensed in respect of the following number of rights either granted or expected to be granted:

Grant Date	Plan Year End	Balance at Start of Year	Granted During the Year	Average Fair Value Per Right	Exercised During the Year	Cancelled or Forfeited During the Year	Balance at End of Year
2021							
11 Nov 2020	30 Jun 2020	—	3,692,054	$0.130	—	—	3,692,054
18 Sep 2020	30 Jun 2018	—	20,271	$0.130	(19,073)	—	1,198
24 Jul 2020	30 Jun 2021	—	9,417,632	$0.065	—	—	9,417,632
24 Jul 2020	30 Jun 2021	—	499,488	$0.089	—	—	499,488
24 Jul 2020	30 Jun 2020	—	30,545	$0.089	—	—	30,545
07 Nov 2019	30 Jun 2019	1,837,109	—	$0.119	—	—	1,837,109
13 Sep 2019	30 Jun 2017	50,700	—	$0.150	(50,700)	—	—
23 Aug 2019	30 Jun 2020	348,708	—	$0.190	—	(37,689)	311,019
23 Aug 2019	30 Jun 2020	7,004,467	—	$0.155	—	(523,625)	6,480,842
09 May 2019	30 Jun 2019	768,542	—	$0.101	—	(11,958)	756,584
17 Apr 2019	30 Jun 2019	49,321	—	$0.111	—	(20,528)	28,793
17 Apr 2019	30 Jun 2019	2,566	—	$0.150	—	—	2,566
24 Sep 2019	30 Jun 2019	5,302,029	—	$0.087	—	(125,875)	5,176,154
24 Sep 2019	30 Jun 2019	321,940	—	$0.120	—	(29,057)	292,883
02 Oct 2018	30 Jun 2016	639	—	$0.067	(639)	—	—
27 Jun 2018	30 Jun 2018	135,920	—	$0.102	—	(135,920)	—
16 May 2018	30 Jun 2018	6,562	—	$0.126	—	(6,562)	—
16 May 2018	30 Jun 2018	10,306	—	$0.175	(10,306)	—	—
01 Sep 2017	30 Jun 2018	4,400,423	—	$0.081	—	(4,400,423)	—
01 Sep 2017	30 Jun 2018	201,222	—	$0.115	(188,722)	—	12,500
20 Oct 2016	30 Jun 2017	517,575	—	$0.106	(517,575)	—	—
20 Oct 2016	30 Jun 2017	11,111	—	$0.135	(11,111)	—	—
09 Nov 2015	30 Jun 2016	6,666	—	$0.184	(6,666)	—	—
Totals		**20,975,806**	**13,659,990**		**(804,792)**	**(5,291,637)**	**28,539,367**

The weighted average fair value of share rights granted under the Long Term Incentive Plan during the year was $0.084 (2020: $0.15). The weighted average remaining contractual life of outstanding share rights at the end of the year was 3.5 years (2020: 3.6 years).

The fair values of deferred share rights granted are valued using methodology that takes into account market and peer performance hurdles. The value of share rights are calculated at the date of grant using a Black Scholes valuation model and Monte Carlo simulations and an agreed comparator group to assess relative total shareholder return.

32. SHARE BASED PAYMENTS (CONTINUED)

(c) Rights to shares — Long Term Incentive Plan (continued)

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during FY2021:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
24 Jul 2020[1]	30 Jun 2025	$0.065	Nil	$0.089	72%	0.43%	—
11 Nov 2020[2]	30 Jun 2025	$0.130	Nil	$0.130	N/A	N/A	—

LTIP Rights for the plan year commencing 1 July 2020.
Deferred share rights issued in lieu of cash under the short term incentive plan for the year commencing 1 July 2019.

Grant Date	Plan Year End	Balance at Start of Year	Granted During the Year	Average Fair Value Per Right	Exercised During the Year	Cancelled or Forfeited During the Year	Balance at End of Year
2020							
07 Nov 2019	30 Jun 2019	—	1,837,109	$0.119	—	—	1,837,109
13 Sep 2019	30 Jun 2017	—	627,417	$0.150	(430,073)	(146,644)	50,700
23 Aug 2019	30 Jun 2020	—	398,520	$0.089	—	(49,812)	348,708
23 Aug 2019	30 Jun 2020	—	7,405,740	$0.155	—	(401,273)	7,004,467
09 May 2019	30 Jun 2019	791,808	—	$0.101	—	(23,266)	768,542
17 Apr 2019	30 Jun 2019	49,321	—	$0.111	—	—	49,321
17 Apr 2019	30 Jun 2019	7,816	—	$0.150	—	(5,250)	2,566
24 Sep 2019	30 Jun 2019	5,784,715	—	$0.087	—	(482,686)	5,302,029
24 Sep 2019	30 Jun 2019	366,711	—	$0.120	—	(44,771)	321,940
02 Oct 2018	30 Jun 2016	639	—	$0.067	—	—	639
27 Jun 2018	30 Jun 2018	135,920	—	$0.102	—	—	135,920
16 May 2018	30 Jun 2018	6,562	—	$0.126	—	—	6,562
16 May 2018	30 Jun 2018	10,306	—	$0.175	—	—	10,306
01 Sep 2017	30 Jun 2018	5,198,232	—	$0.081	—	(797,809)	4,400,423
01 Sep 2017	30 Jun 2018	232,990	—	$0.115	—	(31,768)	201,222
01 Sep 2017	30 Jun 2017	70,000	—	$0.082	(52,500)	(17,500)	—
24 Jan 2017	30 Jun 2017	25,324	—	$0.190	(25,324)	—	—
16 Nov 2016	30 Jun 2017	2,631,108	—	$0.151	(1,518,532)	(1,112,576)	—
20 Oct 2016	30 Jun 2017	6,607,956	—	$0.106	(4,275,334)	(1,815,047)	517,575
20 Oct 2016	30 Jun 2017	338,442	—	$0.135	(319,619)	(7,712)	11,111
09 Nov 2015	30 Jun 2016	6,666	—	$0.184	—	—	6,666
Totals		**22,264,516**	**10,268,786**		**(6,621,382)**	**(4,936,114)**	**20,975,806**

The following factors and assumptions were used in determining the fair value of share rights granted during FY2020:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
09 Aug 2019[1]	13 Sep 2024	$0.155	Nil	$0.155	N/A	N/A	—
23 Aug 2019[2]	30 Jun 2024	$0.155	Nil	$0.190	98%	0.70%	—
13 Sep 2019[3]	08 Dec 2022	$0.150	Nil	$0.200	N/A	N/A	—
07 Nov 2019[4]	12 Nov 2024	$0.119	Nil	$0.170	95%	0.94%	—

1 STIP Rights fully vested on issue – valued at market price at grant date.
2 LTIP Rights for plan year commencing 1 July 2019.
3 Adjustment to number of LTIP Rights for plan year commencing 1 July 2016 – valued at the market price of the known vesting %.
4 LTIP rights issued to L Devaney in respect of the plan year commencing 1 July 2018

32. SHARE BASED PAYMENTS (CONTINUED)

(d) Expenses arising from share-based payment transactions

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

	2021 $	2020 $
Share Rights issued to employees	**1,862,072**	**1,937,011**

33. FINANCIAL RISK MANAGEMENT

The Consolidated Entity's principal financial instruments are cash and short-term deposits. The Consolidated Entity also has other financial assets and liabilities such as trade receivables, trade payables and borrowings, which arise directly from its operations. The Consolidated Entity's risk management objective with regard to financial instruments and other financial assets include gaining interest income and the policy is to do so with a minimum of risk.

(a) Credit Risk

The credit risk on financial assets of the Consolidated Entity which have been recognised in the balance sheet is generally the carrying amount, net of any provision for expected credit losses. The Group applies the simplified approach to providing for expected credit losses prescribed by AASB 9, which permits the use of the lifetime expected loss provision for all trade receivables. Under this method, determination of the loss allowance provision and expected loss rate incorporates past experience and forward-looking information, including the outlook for market demand, the current economic environment, and forward-looking interest rates. As the expected loss rate at 30 June 2021 is nil (2020: nil), no loss allowance provision has been recorded at 30 June 2021 (2020: nil).

The Consolidated Entity trades only with recognised banks and large customers where the credit risk is considered minimal.

Customer credit risk is managed in accordance with the Group's established policy, procedures and controls. Outstanding customer receivables are regularly monitored and relate to the Groups' customers for which there is no history of credit risk or overdue payments. An impairment analysis is performed at each reporting date on an individual basis for the major customers.

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

	Gross		Expected Credit Loss Provision	
Trade and other receivables	**2021 $'000**	2020 $'000	**2021 $'000**	2020 $'000
Current: 0-30 days	**6,084**	5,453	—	—
	6,084	**5,453**	**—**	**—**

The receivables at 30 June 2021 relate predominantly to oil and gas sales which have all been received subsequent to year end.

Credit risk also arises in relation to financial guarantees given by the Parent Entity and other non-borrowing Group entities to certain parties in respect of borrowings by other Group entities (refer Note 25(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific Board approval.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Liquidity Risk

Prudent liquidity risk management implies maintaining sufficient cash and marketable securities and the availability of funding. Management monitors rolling forecasts of the Group's liquidity reserve (comprising the undrawn borrowing facilities below) and cash and cash equivalents (Note 7) based on expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Board of Directors. In addition, the Group's liquidity management policy involves projecting cash flows, monitoring balance sheet liquidity ratios against internal and external regulatory requirements and maintaining debt financing plans.

The Group manages its exposure to key financial risks primarily through supervision by the Audit and Financial Risk Committee. The primary function of this Committee is to assist the Board to fulfil its responsibility to ensure that the Group's internal control framework is effective and efficient.

The following are the contractual maturities of financial assets and liabilities:

2021 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	37,159	—	—	—	37,159	37,159
Trade and other receivables	6,084	—	—	—	6,084	6,084
Other financial assets	—	—	4,218	—	4,218	4,218
	43,243	**—**	**4,218**	**—**	**47,461**	**47,461**
Financial Liabilities						
Trade and other payables	(10,491)	—	—	—	(10,491)	(10,491)
Interest bearing liabilities	(33,245)	(5,221)	(32,271)	(123)	(70,860)	(68,318)
	(43,736)	**(5,221)**	**(32,271)**	**(123)**	**(81,351)**	**(78,809)**

2020 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	25,918	—	—	—	25,918	25,918
Trade and other receivables	5,453	—	—	—	5,453	5,453
Other financial assets	—	—	2,656	—	2,656	2,656
	31,371	**—**	**2,656**	**—**	**34,027**	**34,027**
Financial Liabilities						
Trade and other payables	(5,073)	(214)	—	—	(5,287)	(5,287)
Interest bearing liabilities	(5,355)	(6,227)	(64,837)	(143)	(76,562)	(71,999)
	(10,428)	**(6,441)**	**(64,837)**	**(143)**	**(81,849)**	**(77,286)**

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Interest Rate Risk

The Consolidated Entity's exposure to interest rate risk, which is the risk that a financial instrument's value will fluctuate as a result of changes in market interest rates and the effective weighted average interest rates on classes of financial assets and financial liabilities, is as follows:

	Weighted Average Effective Interest Rate		Floating Interest Rate		Fixed Interest		Non-Interest-Bearing		Total	
	2021 %	2020 %	**2021 $'000**	2020 $'000	**2021 $'000**	2020 $'000	**2021 $'000**	2020 $'000	**2021 $'000**	2020 $'000
Financial Assets:										
Cash and cash equivalents	0.3	0.3	37,159	25,918	—	—	—	—	37,159	25,918
Trade and other receivables	—	—	—	—	—	—	6,084	5,453	6,084	5,453
Other financial assets	0.0	0.2	—	—	908	1,083	3,310	1,573	4,218	2,656
Total Financial Assets			**37,159**	**25,918**	**908**	**1,083**	**9,394**	**7,026**	**47,461**	**34,027**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(10,491)	(5,287)	(10,491)	(5,287)
Interest bearing liabilities	5.6	5.6	(66,809)	(70,773)	(1,509)	(1,226)	—	—	(68,318)	(71,999)
Total Financial Liabilities			**(66,809)**	**(70,773)**	**(1,509)**	**(1,226)**	**(10,491)**	**(5,287)**	**(78,809)**	**(77,286)**
Net Financial Assets / (Liabilities)			**(29,650)**	**(44,855)**	**(601)**	**(143)**	**(1,097)**	**1,739**	**(31,348)**	**(43,259)**

Interest Rate Sensitivity

A sensitivity of 10% has been selected as this is considered reasonable given the current level of both short term and long term interest rates. A 10% movement in interest rates at the reporting date would have increased/(decreased) equity and profit and loss by the amounts shown below based on the average balance of interest-bearing financial instruments held. This analysis assumes that all other variables remain constant.

The analysis is performed only on those financial assets and liabilities with floating interest rates and is prepared on the same basis as for 2020.

	Profit or Loss		Equity	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2021 ($'000)				
Cash and cash equivalents	13	(13)	—	—
Interest bearing liabilities	(369)	369	—	—
2020 ($'000)				
Cash and cash equivalents	7	(7)	—	—
Interest bearing liabilities	(397)	397	—	—

These movements would not have any impact on equity other than retained earnings.

(d) Commodity Risk

The majority of gas sales are made under long term contracts and as such do not contain any commodity risk for the duration of the contract. The Consolidated Entity is exposed to commodity price fluctuations in respect of recorded crude oil sales and gas sales which are not subject to long term fixed price contracts. The effect of potential fluctuations is not considered material to balances recorded in these financial statements. The Board's current policy is not to hedge crude oil sales. The Board will continue to monitor commodity price risk and take action to mitigate that risk if it is considered necessary in light of the Group's overall product sales mix and forecast cash flows.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(e) Financing Facilities

The Group has a loan facility agreement (Facility) with Macquarie Bank Limited (Macquarie).

Interest costs are based on fixed spreads over the periodic Bank Bill Swap (BBSW) average bid rate. The Facility is structured as a partially amortising term loan and has a maturity date of 30 September 2022 (2020: 30 September 2021). Repayments comprise fixed quarterly principal repayments of $1,000,000 along with accrued interest to September 2021 and $2,000,000 per quarter thereafter. In addition, the Group has committed to a lump sum repayment of $29,000,000 from the proceeds of the sell down of its producing assets, which is expected to complete on 1 October 2021. Therefore, as at 30 June 2021, there is not an unconditional right to defer settlement of this amount for at least 12 months and $29,000,000 has been classified as “current” in the Balance Sheet. If the transaction does not complete, this amount of $29,000,000 would revert to being payable on 30 September 2022. The Group does not have any interest rate hedging arrangements in place.

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

1. The Group Current Ratio is at least 1:1, excluding amounts payable under the Macquarie debt facility and certain liabilities associated with gas sales agreements with Macquarie Bank.
2. The Net Present Value with a 10% discount rate (NPV10) of forecasted net cash flow from the Palm Valley, Dingo and Mereenie gas fields limited by the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount must be greater than 1.3:1.

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

(f) Currency Risk

The Consolidated Entity’s exposure to currency risk is limited due to its ongoing operations being in Australia and most associated contracts completed in Australian dollars. A foreign exchange risk arises from oil sales denominated in US dollars and from liabilities denominated in a currency other than Australian dollars. The Group generally does not undertake any hedging or forward contract transactions as the exposure is considered immaterial, however, individual transactions are reviewed for any potential currency risk exposure.

At reporting date, the Group had the following exposure to foreign currency risk for balances denominated in foreign currencies from its continuing operations, which are disclosed in Australian dollars:

	2021 $’000	2020 $’000
Trade and other receivables (USD)	1,609	677
Trade and other payables :		
- USD	(416)	(153)
- GBP	(3)	—
- EUR	(3)	—

The following table details the Group’s Profit or Loss sensitivity to a 10% increase or decrease in the Australian dollar against the foreign currency, with all other variables held constant. The sensitivity analysis is based on the foreign currency risk exposure at the reporting date.

	2021 $’000	2020 $’000
Australian dollar +10% movement in exchange rate	(108)	(62)
Australian dollar -10% movement in exchange rate	132	75

These movements would not have any impact on equity other than retained earnings.

(g) Fair Values

The carrying amounts of cash, cash equivalents, financial assets and financial liabilities, approximate their fair values.

34. INTERESTS IN JOINT ARRANGEMENTS

Details of joint arrangements in which the Consolidated Entity has an interest and the name of the party with joint control are as follows:

	Principal Activities	2021 %	2020 %
OL4, OL5 and PL2 Mereenie (Macquarie[1])	Oil & gas production	50.00	50.00
EP 82 (Santos[2])	Oil & gas exploration	60.00	60.00
EP 105 (Santos[2])	Oil & gas exploration	60.00	60.00
EP 112 (Santos[2])	Oil & gas exploration	30.00	30.00
EP 125 (Santos[2])	Oil & gas exploration	30.00	30.00
EP 115 North Mereenie Block (Santos[2])	Oil & gas exploration	100.00	100.00
EPA 111 (Santos[2])	Oil & gas exploration – application	50.00	50.00
EPA 124 (Santos[2])	Oil & gas exploration – application	50.00	50.00
ATP 2031 Range Gas Project (IPL[3])	Oil & gas exploration	50.00	50.00

1 Macquarie = Macquarie Mereenie Pty Ltd.
2 Santos = Santos Group companies.
3 IPL = Incitec Pivot Limited.

The Joint Arrangements are accounted for based on contributions made to the Joint Operated Arrangements on an accruals basis. The principal place of business is Australia.

Santos' right to earn and retain participating interests in each permit is subject to satisfying various obligations in their respective farmout agreement. The participating interests as stated assume such obligations have been met, or otherwise may be subject to change or negotiation.

34. INTERESTS IN JOINT ARRANGEMENTS (CONTINUED)

The share in the assets and liabilities of the joint arrangements where less than 100% interest is held by the Company are included in the Consolidated Entity's balance sheet in accordance with the accounting policy described in Note 1(b)(ii) under the following classifications:

	2021 $'000	2020 $'000
Current assets		
Cash and cash equivalents	878	666
Trade and other receivables	4,424	4,243
Inventory	722	1,409
Assets classified as held for sale	29,227	—
Total current assets	35,251	6,318
Non-current assets		
Property, plant and equipment	28,264	52,074
Right of use assets	87	225
Other financial assets	1,328	301
Total non-current assets	29,679	52,600
Current liabilities		
Trade and other payables	3,382	3,494
Lease liabilities	25	46
Deferred revenue	365	731
Provision for production over-lift	734	712
Restoration provision	—	119
Liabilities directly associated with assets classified as held for sale	13,370	—
Total current liabilities	17,876	5,102
Non-current liabilities		
Deferred revenue	219	439
Lease liabilities	70	187
Provision for production over-lift	2,830	3,461
Restoration provision	12,800	21,433
Total non-current liabilities	15,919	25,520
Net assets	**31,135**	**28,296**
Joint arrangement contribution to loss before tax		
Revenue	35,248	38,541
Other income	12	10
Expenses	(30,172)	(26,849)
Profit before income tax	**5,088**	**11,702**

35. EVENTS OCCURRING AFTER THE REPORTING PERIOD

Increased interest in EP112

Effective 31 July 2021, Central's interest in EP112 increased from 30% to 45% as a result of joint venturer, Santos, not electing that Central be carried for the first $3,000,000 of future Dukas well costs.

Asset Sale

On 17 September 2021 the agreement for the sale of 50% of the Group's producing assets to New Zealand Oil & Gas Limited and Cue Energy Resources Limited became unconditional and the transaction is expected to complete on 1 October 2021.

No other matter or circumstance has arisen between 30 June 2021 and the date of this report that will affect the Group's operations, result or state of affairs, or may do so in future years.

DIRECTORS' DECLARATION

1. In the Directors' opinion:

   a) the financial statements and notes set out on pages 52 to 98 of the Consolidated Entity are in accordance with the *Corporations Act 2001* (Cth), including:

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

      (ii) giving a true and fair view of the Consolidated Entity's financial position as at 30 June 2021 and of its performance for the financial year ended on that date;

   b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable; and

   c) the financial statements comply with the International Financial Reporting Standards as issued by the International Accounting Standards Board as disclosed in Note 1(a).

2. This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the *Corporations Act 2001* (Cth) for the financial year ended 30 June 2021.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in Note 27 will be able to meet any obligations or liabilities to which they are or may become subject by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly owned Companies) Instrument 2016/785.

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

Michael McCormack
Director
Brisbane

21 September 2021

Independent auditor's report

To the members of Central Petroleum Limited

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Central Petroleum Limited (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 30 June 2021 and of its financial performance for the year then ended

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

What we have audited

The Group financial report comprises:

- the consolidated balance sheet as at 30 June 2021
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- the consolidated statement of comprehensive income for the year then ended
- the notes to the consolidated financial statements, which include a summary of significant accounting policies
- the directors' declaration.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

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

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.

Materiality	*Audit scope*	*Key audit matters*
• For the purpose of our audit, we used overall Group materiality of $1.74 million, which represents approximately 1% of the Group's total assets. • We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole. • We chose Group's total assets because, in our view, it is the benchmark against which the performance of the Group is most commonly measured and is a generally accepted benchmark in the oil and gas industry for entities at a similar stage of development. • We utilised a 1% threshold based on our professional judgement, noting it is within the range of commonly acceptable thresholds.	• Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events. • The Group produces oil and gas from its interests in fields in the Northern Territory and continues to conduct exploration and evaluation activities in respect of tenements located in the Northern Territory and Queensland.	• Amongst other relevant topics, we communicated the following key audit matter to the Audit and Risk Committee: - Sell-down of Amadeus Basin Production Assets

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context.

Key audit matter	*How our audit addressed the key audit matter*

Sell-down of Amadeus Basin Production Assets *(Refer to notes 10, 11 and 16)*
 	
During the year, the Group entered into a binding agreement with New Zealand Oil and Gas Limited ("NZOG") and Cue Energy Resources Limited ("Cue") to sell 50% of its interest in the Amadeus Basin Production Assets.
 	
The transaction is subject to various regulatory and other approvals.
 	
The sell-down transaction was a key audit matter because:
• of the significance of the assets ($57.97 million) and related liabilities ($39.44 million) classified as held for sale due to this transaction.
• the transaction price has been used by the Group to determine fair value and therefore, assess the recoverable amount of:
  ○ assets and liabilities held for sale
  ○ goodwill and the producing assets cash-generating unit (CGU).
	To evaluate the Group's assessment of the assets and liabilities classified as held for sale, we performed a number of procedures including the following:
	• Obtained and read the signed binding agreement with NZOG and Cue and inspected evidence of progress against conditions precedent for completion.
	• Reconciled the assets and liabilities classified and disclosed as held for sale to the key terms and clauses of the signed binding agreement.
	• Assessed whether the assets and liabilities held for sale met the definition of a discontinuing operation under Australian Accounting Standard AASB 5 *Non-current assets held for sale and discontinued operations*.
	
	To evaluate the Group's assessment of recoverable amount of the assets and liabilities held for sale, goodwill and the producing assets CGU, we performed a number of procedures including the following:
	• Compared the fair value less costs to sell by the Group (based on the signed binding agreement) to the carrying value and the resulting recoverable amount of the total assets classified as held for sale less total liabilities directly associated with such assets.
	• Assessed whether the composition of the producing assets CGU was consistent with our knowledge of the Group's operations.
	• Assessed whether the CGU appropriately included all directly attributable assets and liabilities.
	• Assessed if the transaction price as per the signed binding agreement meets the definition of fair value less costs of disposal (FVLCD) in Australian Accounting Standard AASB 136 *Impairment of Assets* and Australian Accounting Standard AASB 13 *Fair Value Measurement*.
	• Tested the inputs and the mathematical accuracy of the calculation to determine the recoverable amount of goodwill and producing assets CGU.
	• Evaluated the adequacy of disclosures made in note 16 of the financial statements, including those regarding selection of method to compute fair value less costs of disposal in light of the requirements of the Australian Accounting Standards.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2021, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: https://www.auasb.gov.au/admin/file/content102/c3/ar1_2020.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 35 to 49 of the directors' report for the year ended 30 June 2021.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2021 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Marcus Goddard
Partner

Brisbane
21 September 2021

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 15 SEPTEMBER 2021

Top holders

The 20 largest registered holders of the quoted securities as at 15 September 2021 were:

	Name	No. of Shares	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	37,500,000	5.18
2	UBS Nominees Pty Ltd	29,914,670	4.13
3	Fanchel Pty Ltd	17,700,000	2.44
4	Mr Christopher Ian Wallin + Ms Fiona Kay McLoughlin + Mrs Sylvia Fay Bhatia <Chris Wallin Super Fund A/C>	17,571,648	2.43
5	Brazil Farming Pty Ltd	16,385,209	2.26
6	Citicorp Nominees Pty Limited	15,568,444	2.15
7	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.96
8	Chembank Pty Limited <Philandron A/C>	10,000,000	1.38
9	Mr Raymond Driscoll + Mrs Karyn Driscoll + Mr Jarrod Driscoll <The Edwin Holdings S/F A/c>	8,936,608	1.23
10	Mr Philip Gasteen <Thrushton Investment A/C>	8,583,800	1.19
11	Kensington Capital Partners Pty Ltd	8,000,000	1.10
12	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	7,500,000	1.04
13	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	7,000,000	0.97
14	Mr Stuart Francis Howes	6,076,001	0.84
15	Mr Donald Leonard Cottee	5,830,594	0.81
16	Mr William Bambling + Mrs Joyce Bambling	5,205,000	0.72
17	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/C>	5,000,001	0.69
18-19	Chembank Pty Limited <R T Unit A/C>	5,000,000	0.69
18-19	Garmi Holdings Pty Ltd	5,000,000	0.69
20	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	4,000,000	0.55
	Total	**234,938,642**	**32.45**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 15 September 2021 was:

	Number of Holders		
Size of Holding	Listed Fully Paid Shares	Unlisted Share Rights	Unlisted Options
1 - 1,000	741	1	—
1,001 -5,000	1,802	8	—
5,001 - 10,000	1,025	12	—
10,001 - 100,000	2,552	42	—
100,001 - Over	955	29	5
Total	**7,075**	**92**	**5**

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 15 September 2021 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

Holder	Units
Troy Harry	55,000,000

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 4,762 shares as at 15 September 2021):

Holders	Units
2,370	4,456,385

VOTING RIGHTS

Subject to any rights or restrictions for the time being attached to any class or classes of shares, at meetings of shareholders or classes of shareholders:

- each shareholder entitled to vote may vote in person or by proxy, attorney or representative of a shareholder;
- on a show of hands, every person present who is a shareholder or a proxy, attorney or representative of a shareholder has one vote; and
- on a poll, every person present who is a shareholder shall, in respect of each fully paid share held by him, or in respect of which he is appointed a proxy, attorney or representative, have one vote for their share, but in respect of partly paid shares, shall have such number of votes being equivalent to the proportion which the amount paid (not credited) is of the total amounts paid and payable in respect of those shares (excluding amounts credited).

ON-MARKET BUY-BACK

There is no current on-market buy-back of the Company's securities.

CORPORATE GOVERNANCE STATEMENT

Central Petroleum Limited and its Board are committed to achieving and demonstrating high standards of corporate governance. The Company has reviewed its corporate governance practices against the Corporate Governance Principles and Recommendations (4th edition) published by the ASX Corporate Governance Council.

The 2021 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2021 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

AT THE DATE OF THIS REPORT

PERMITS AND LICENCES GRANTED

			CTP Consolidated Entity		Other JV Participants	
Tenement	Location	Operator	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP82 (excl. EP82 Sub-Blocks)	Amadeus Basin NT	Santos	60	60	Santos QNT Pty Ltd (Santos)	40
EP82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP105	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP112 [1]	Amadeus Basin NT	Santos	30	45	Santos	55
EP115 (excl. EP115 North Mereenie Block)	Amadeus Basin NT	Central	100	100		
EP115 North Mereenie Block[2]	Amadeus Basin NT	Santos	60	100		
EP125	Amadeus Basin NT	Santos	30	30	Santos	70
OL3 (Palm Valley)[3]	Amadeus Basin NT	Central	100	100		
OL4 (Mereenie) [3]	Amadeus Basin NT	Central	50	50	Macquarie Mereenie Pty Ltd (Macquarie Mereenie)	50
OL5 (Mereenie) [3]	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
L6 (Surprise)	Amadeus Basin NT	Central	100	100		
L7 (Dingo) [3]	Amadeus Basin NT	Central	100	100		
RL3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL4 (Ooraminna)	Amadeus Basin NT	Central	100	100		
ATP909	Georgina Basin QLD	Central	100	100		
ATP911	Georgina Basin QLD	Central	100	100		
ATP912	Georgina Basin QLD	Central	100	100		
ATP2031 (Range Gas Project)	Surat Basin QLD	Central	50	50	Incitec Pivot Queensland Gas Pty Ltd	50

PERMITS AND LICENCES UNDER APPLICATION

			CTP Consolidated Entity		Other JV Participants	
Tenement	Location	Operator	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA92	Wiso Basin NT	Central	100	100		
EPA111	Amadeus Basin NT	Santos	100	50	Santos	50
EPA120	Amadeus Basin NT	Central	100	100		
EPA124 [4]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA129	Wiso Basin NT	Central	100	100		
EPA130	Pedirka Basin NT	Central	100	100		
EPA131 [5]	Pedirka Basin NT	Central	100	0		
EPA132	Georgina Basin NT	Central	100	100		
EPA133 [6]	Amadeus Basin NT	Central	100	100		
EPA137	Amadeus Basin NT	Central	100	100		
EPA147	Amadeus Basin NT	Central	100	100		
EPA149	Amadeus Basin NT	Central	100	100		
EPA152 [4]	Amadeus Basin NT	Central	100	100		
EPA160	Wiso Basin NT	Central	100	100		
EPA296	Wiso Basin NT	Central	100	100		

PIPELINE LICENCES

			CTP Consolidated Entity		Other JV Participants	
Pipeline Licence	Location	Operator	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
PL2 [3]	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
PL30 [3]	Amadeus Basin NT	Central	100	100		

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

AT THE DATE OF THIS REPORT

Notes:

[1] 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 as a result, Santos' interest will decrease from 70% to 55% (Central's interest will increase from 30% to 45%).

[2] On 12 December 2019 Central received notice from Santos of its intention to withdraw from EP115 North Mereenie Block effective 31 January 2020.

[3] On 25 May 2021 Central announced an agreement to sell 50% of its existing interests in Mereenie, Palm Valley and Dingo to subsidiaries of New Zealand Oil & Gas Ltd and Cue Energy Resources Ltd. The transaction is expected to settle on 1 October 2021.

[4] On 22 March 2018 (in respect EPA124) and on 23 March 2018 (in respect of EPA152) Central received notice from the NT Department of Primary Industry and Resources that EPA124 and EPA152, as applicable, had been placed in moratorium for a period of 5-years from 6 December 2017 until 6 December 2022.

[5] The exploration permit application has been disposed. Transfer of the registered interest is awaiting the grant of an exploration permit.

[6] 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.

CORPORATE DIRECTORY

CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

DIRECTORS

Mr Michael (Mick) McCormack BSurv, GradDipEng, MBA, FAICD, Non-Executive Director, Chair
Mr Leon Devaney BSc MBA, Managing Director and Chief Executive Officer
Mr Stuart Baker BE(Elec), MBA, AICD, Non-Executive Director
Mr Stephen Gardiner BEc (Hons), Fellow - CPA Australia
Ms Katherine Hirschfeld AM, BE(Chem), HonFIEAust, FTSE, FIChemE, FAICD, Non-Executive Director
Dr Agu Kantsler BSc (Hons), PhD, GAICD, FTSE, Non-Executive Director

GROUP GENERAL COUNSEL AND COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

REGISTERED OFFICE

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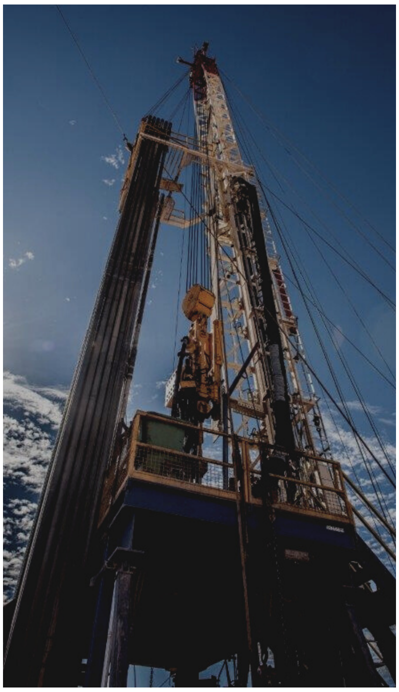
STOCK EXCHANGE LISTING

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



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