Central Petroleum

2020 ANNUAL REPORT

Central Petroleum Limited

ACN 083 254 308

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Forward-looking statements:

This document contains forward-looking statements, including (without limitation) statements of current intention, opinion, predictions and expectations regarding Central's present and future operations, possible future events and future financial prospects. Such statements are not statements of fact, are not certain and are susceptible to change and may be affected by a variety of known and unknown risks, variables and changes in underlying assumptions or strategy that could cause Central's actual results or performance to differ materially from the results or performance expressed or implied by such statements. There can be no certainty of outcome in relation to the matters to which the statements relate. Central makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward-looking statement (whether express or implied) or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in this document reflect expectations held at the date of this document. Except as required by applicable law or the Australian Securities Exchange (ASX) Listing Rules, Central disclaims any obligation or undertaking to publicly update any forward-looking statements.

CHAIRMAN'S LETTER

Dear Fellow Shareholders

At the Annual General Meeting in November last year, no one could have predicted within the next quarter, the world and all our lives would become so seriously impacted by a global pandemic. This year has highlighted the importance of having the stability, financial strength and flexibility to be able to ride-out the downturn and recession caused by the pandemic, while having the capability to capitalise on the opportunities that inevitably arise.

Just a few years ago, Central's circumstances would have required drastic action to ride-out today's conditions. However, I am pleased today's Central has a new resilience built on a strong portfolio of producing gas fields, backed by long-term, fixed-price gas sales contracts.

The market disruption may have taken some gloss from the annual results, but the underlying numbers can't be ignored. This year we have recorded our first full year profit after tax, posted record sales volumes and revenues, and upgraded our booked reserves.

This outcome is the culmination of strategic positioning and successful execution to expand production capacity to take advantage of new access to eastern markets through the Northern Gas Pipeline (NGP) which was commissioned in January 2019.

We are excited by the recently announced proposal to construct the Amadeus to Moomba Gas Pipeline (AMGP). The AMGP is a shorter, more direct route, with fewer bottlenecks to deliver our gas to the increasingly short southern markets and should result in increased sales volumes and higher margins for Central.

Oil and gas has been produced from the Amadeus Basin for decades, but its potential has been limited by distance to market. Completion of the AMGP, a second pipeline connection to the east within 5 years of the NGP, would be a 'game-changer' for Central, providing a catalyst for the Amadeus Basin to become an increasingly important part of the solution for south-eastern Australia's looming gas shortage.

It is easy to be distracted by the current weakness in gas spot prices, but forecasts indicate southern Australia will see a major and continuing shortage of gas from 2023 as gas supplies continue to decline from the 50-year old Bass Strait fields, exacerbated by the planned closure of coal-fired power stations, such as the Liddell Power Station in NSW. Central's next phase of growth will target this market supply opportunity.

A successful return to the much-anticipated Dukas well in 2022 could also provide a huge new resource for southern markets and we are already working on other large potential sub-salt leads in the basin. In Queensland, we added 135 PJ of 2C contingent resource at our Range Gas Project and are aiming to reach a final investment decision next year, with first gas production targeted for 2023.

The value of our producing assets and growth potential is clear, and our challenge now is to deliver a successful exploration programme in 2021, followed by a Final Investment Decision (FID) for the Range Gas Project and the AMGP. At the same time, we will continue to build on the relationships we have established with our valued stakeholders. As a proud Australian company, we are continuing to deliver on our 'buy local and employ local' policy to provide employment and business opportunities to the local communities and Traditional Owners in the areas where we operate.

There has been continuing discussion about the gas growth story and the role natural gas can play as global economies transition from coal to renewable energy sources. It is clear that gas has an important role to play in reducing emissions while maintaining the stability and reliability of energy generation. Australia's Chief Scientist, Alan Finkle has stated that Australia's electricity supply will remain dependent on "complementary" gas power for up to 30 years as the nation's grids make the transition to zero emissions renewable energy. Consistent with the Federal Government's recently announced Energy Plan, our continuing investment in exploration and growth projects and commitment to pipeline infrastructure can assist in this transition process.

Environmental impacts from our operations in the Amadeus Basin remain relatively small. We do not extract and discharge CO_2 due to the extremely low levels contained in our produced gas. We use proven conventional drilling techniques to extract our gas and our planned development and exploration programmes do not require fracking.

Our strategy for success includes building a team with the right balance of skills, experience and vision to deliver on our plans. Importantly we have added two very experienced professionals to our Board in recent months—former Woodside Executive Vice President of Exploration, Dr Agu Kantsler and former APA Group MD, Mick McCormack. Agu and Mick bring many years of industry experience to the Board and share our confidence in our business and growth strategy.

Our good news story for this year has been our resilience in the face of the global pandemic. For FY2021, we aim to build upon our established production base through a mix of continuing field development and high impact exploration.

With the successful delivery of these exciting growth projects, I am confident that the value of our impressive asset portfolio in the Northern Territory and Queensland will become more widely recognised.

In conclusion, I wish to thank the Traditional Owners of the land on which we operate and to thank all our shareholders for your support of your Board and management as we continue to progress through these challenging times.

Thank you,

Wrixon Gasteen, Chairman
24 September 2020

CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders

Since last year's Annual Report CEO Letter, we have seen some very challenging business conditions. Throughout this turbulence, I have been buoyed by the underlying resilience and stability of Central Petroleum's producing assets and people, which has us well-placed to launch into a substantial new phase of growth.

FY2020 has been a year of two halves. The first half saw good momentum with:

- continuing high gas and oil production from our recently upgraded fields in the Northern Territory
- a successful Range exploration programme delivering 135 PJ of new 2C gas resources in the Surat Basin
- positive indicators of hydrocarbon-bearing gas from an over-pressurised zone at the much-anticipated, but now suspended, Dukas-1 exploration well
- announcement of a major new Amadeus Basin exploration programme that has Company-changing potential.

The second half turned into an uphill climb very quickly, with a severe downturn in global energy markets and heightened business uncertainty as COVID-19 emerged into a pandemic. This tested our resilience and flexibility and, in so doing, highlighted an often-unrecognised pillar of our business strategy: stronger financial foundations through quality operating assets that protect shareholder value through downturns.

Although the full-year financial results for FY2020 were impacted by the energy market downturn, it was still a record year for sales volumes for Central, which were up 14% to 12.3 PJE generating revenue of $65M. Our earnings before interest, tax, depreciation, amortisation and exploration (EBITDAX) were $33 million, up 51% on FY2019 and easily covering (2.0x) service of loan facilities of $16.4M, which included accelerated principal repayments of $11.5M. Importantly, our portfolio of fixed-price, long-term gas supply contracts have provided sufficient cash flow after debt service to cover our operating and corporate costs.

There were a number of other business highlights, including:

- 16% increase in 2P reserves
- 12-month extension to our finance facilities
- maintained a strong cash balance of $26M
- reached JV agreement on a forward plan for the multi-Tcf Dukas prospect.

Our planned exploration programme in the Amadeus Basin is a great opportunity for Central to quickly accelerate production by targeting formations known to be productive in other areas and located in or near existing producing fields and infrastructure. While we have a seriatim of attractive exploration targets, our immediate focus is to drill three exploration wells next year targeting circa 600 PJ of mean prospective resources.

Our Range Gas Project in Queensland's Surat Basin is another key part of Central's growth strategy, with 135 PJ (net to Central) of 'development-pending' 2C contingent gas resources, anticipated to have significant value as a future source of east coast gas supply. After pausing activity earlier this year, we are seeking to restart Range pre-FID activity as quickly as possible in an effort to achieve FID in late 2021 (with potential to nearly double our 2P reserves) and target first gas in late 2023 (nearly doubling current gas sales).

As part of our forward plan for Dukas, we are now working with our JV partner Santos to recommence drilling in 2022. There remains enormous upside in the large, yet underexplored Amadeus Basin, and a return to the multi-Tcf Dukas prospect and future exploration at another large sub-salt lead (Zevon) in EP115 are both opportunities to find major new multi-Tcf gas supply for the east coast domestic market.

Our growth strategy is bold and positioned to take full advantage of what I believe will be a strong recovery in the domestic gas market from 2022. But our vision for where Central can go from here should be even more exciting for shareholders. Until only recently, the Amadeus Basin was remote, isolated and generally 'flew under the radar'. It is now becoming recognised as one of the best onshore opportunities to deliver material new gas supplies to the east coast market, with decades of proven gas production, significant existing 2P reserves and massive conventional and unconventional prospective resources.

Whilst commencement of the Northern Gas Pipeline last year was a catalyst for increased activity in the Amadeus Basin, we recently entered into an MOU to progress the Amadeus to Moomba Gas Pipeline (AMGP) with Macquarie Mereenie and Australian Gas Infrastructure Group (AGIG). The AMGP more than halves the distance that our gas would travel to Moomba, with the prospect of significantly lower tariffs. This would open up a major new cost-efficient gas supply from the Amadeus Basin for the southern east coast market, which will be increasingly short on gas.

Funding Company-changing growth strategies remains a key focus, particularly given the scope of activity relative to our size and the current weak market conditions. We have been actively pursuing a range of alternatives and, as we have done in the past, our funding strategy will seek to maximise shareholder value. The current process for a partial sell-down of our existing Amadeus Basin assets continues to be encouraging, with interest reinvigorated following recent announcements on the AMGP and the Federal Government's Energy Plan. Given the significance of a partial sell-down, it is critical that we don't rush, but instead take the time necessary to get the best outcome with the right partner.

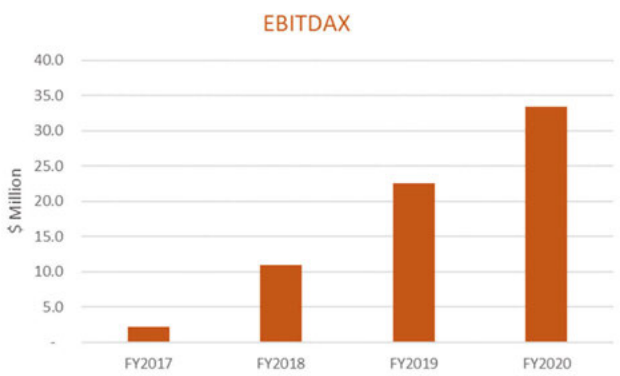
I would like to take this opportunity to thank our dedicated staff for safely, effectively and efficiently operating our business throughout the year. A number of our field personnel spent extended periods away from family and friends to keep our fields operating through the COVID-19 border closures. Their efforts and dedication are at the heart of Central's successes.

I also wish to thank our many stakeholders for their continued support during a very challenging year. As the past year has clearly demonstrated, challenges and opportunities are both part of this business. With our strong Board, experienced management and dedicated employees, I have every confidence that our growth strategies will be delivered, and their value recognised in the market.

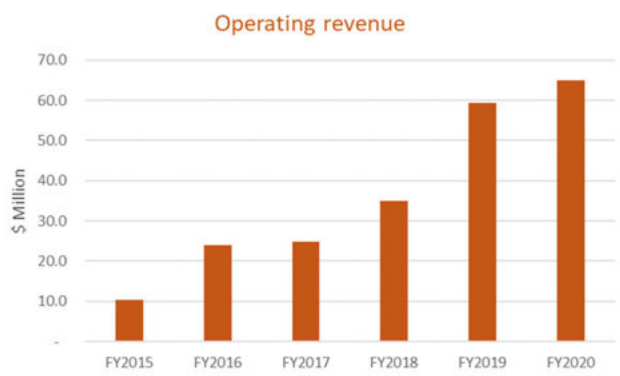
Leon Devaney, CEO
24 September 2020

OPERATING HIGHLIGHTS

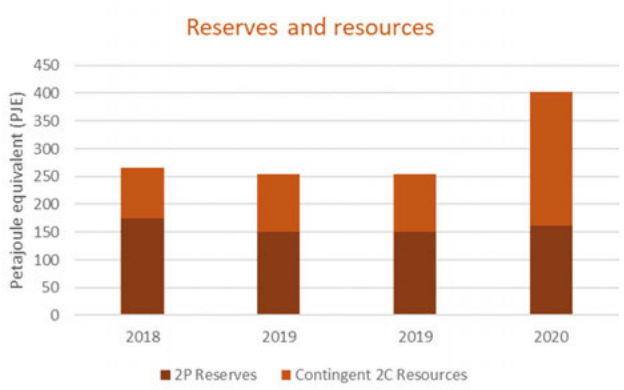
- Record annual sales volumes and revenues:
  - Volumes up 14% to 12.3 PJE
  - Revenues up 10% to $65 million.
- 51% increase in EBITDAX to $33.4 million.
- Maiden full year profit of $5.4 million.
- 16% increase in 2P reserves to 161.2 PJE.
- Added 135 PJ of 2C contingent gas reserves (Central share) at the Range Gas Project in the Surat Basin after completion of a successful four well exploration programme.
- Dukas-1 well was suspended after encountering hydrocarbon-bearing gas from an over-pressured zone close to the primary target and a forward plan to complete the Dukas exploration programme is now underway.
- Excellent safety record with no MTIs or LTIs during the year.
- Reduced net debt by 30% to $46.1 million and extended loan facility by 12 months to late 2021.
- Strengthened the Board with the appointment of Dr Agu Kantsler and Mr Mick McCormack, both highly respected industry leaders with proven experience in the core areas critical to Central's future success.
- Subsequent to the year end, announced an MOU with highly capable partners, Macquarie Mereenie and Australian Gas Infrastructure Group (AGIG), to progress towards a final investment decision on a proposed major new pipeline to 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.



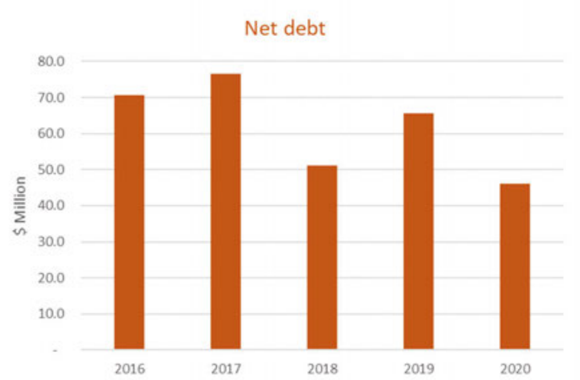
EBITDAX: Increased 51% to $33.4m in FY2020
(Earnings before interest, tax, depreciation, impairment and exploration costs)



Operating revenue: Increased 10% to $65m in FY2020



Reserves & Resources: 2P reserves up 16% to 161.2 PJE and 135 PJ of 2C resources added



Net Debt: decreased by 30% to $46.1 million at 30 June 2020

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a profit after income tax for the year ended 30 June 2020 of $5.4 million (2019: loss of $14.5 million).

The above result was after expensing exploration costs of $5.3 million (2019: $15.8 million). The Group's policy is to expense all exploration costs as incurred.

The table below shows key metrics for the Group:

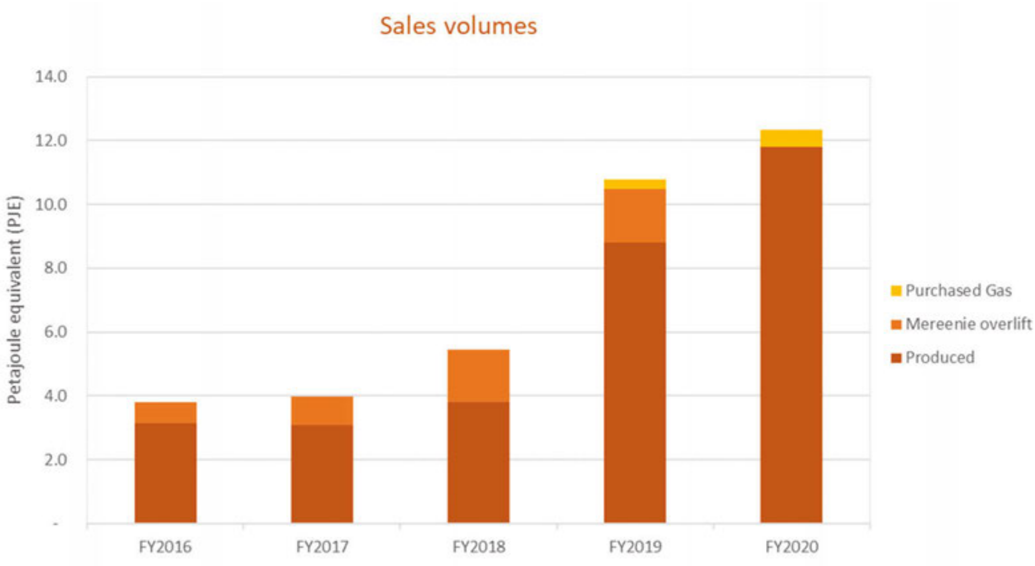
Key Metrics	Total 2020	Total 2019	Change	% Change
Net Sales Volumes				
- Natural Gas (TJ)	11,822	10,229	1,593	16%
- Oil & Condensate (bbls)	89,016	97,392	(8,376)	(9)%
Sales Revenue ($'000)	65,046	59,358	5,688	10%
Gross Profit ($'000)	31,660	28,989	2,671	9%
EBITDAX[1] ($'000)	33,403	22,186	11,217	51%
EBITDA[2] ($'000)	28,126	6,384	21,742	341%
EBIT[3] ($'000)	11,692	(6,312)	18,004	N/A
Statutory profit/(loss) after tax ($'000)	5,411	(14,526)	19,937	N/A
Net cash inflow from Operations[4] ($'000)	15,727	2,465	13,262	538%
Capital expenditure[5] ($'000)	2,857	16,188	(13,331)	(82)%

[1] *EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs (refer reconciliation below).*
[2] *EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation and Impairment.*
[3] *EBIT is Earnings before Interest and Taxation.*
[4] *Cashflow from Operations includes cash outflows associated with Exploration activities.*
[5] *Capital expenditure on tangible assets.*

Reconciliation of statutory profit/(loss) before tax to EBITDAX	2020 $'000	2019 $'000
Statutory profit/(loss) before tax	5,411	(14,526)
Net finance costs	6,281	8,215
EBIT	**11,692**	**(6,311)**
Depreciation and amortisation	16,257	12,695
Impairment	177	—
EBITDA	**28,126**	**6,384**
Exploration expenses	5,277	15,802
EBITDAX	**33,403**	**22,186**

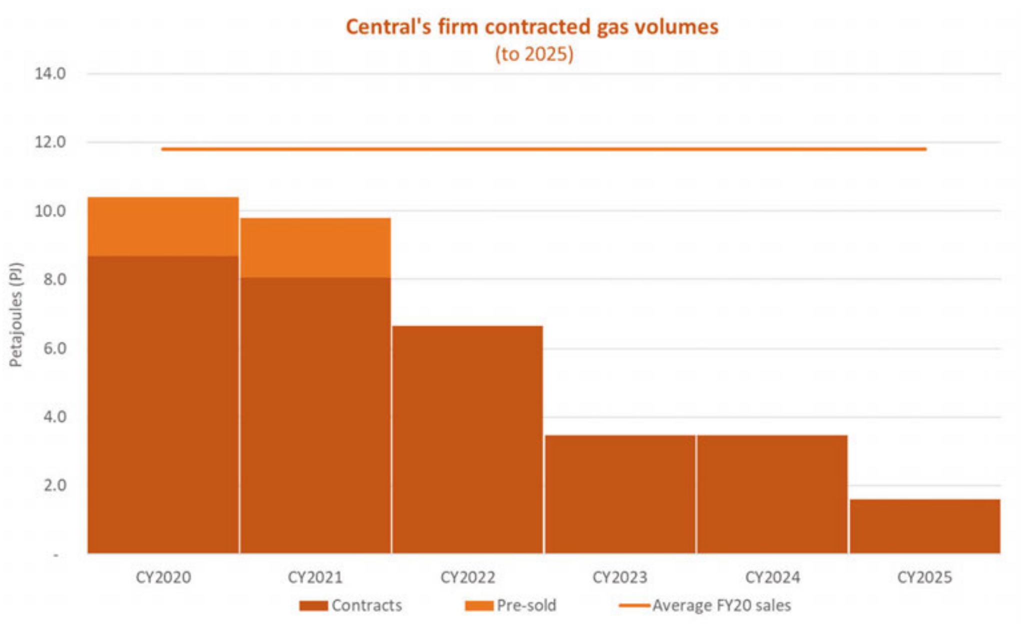
Sales Volumes

Sales volumes were 14% higher than FY2019 at 12.34 PJE, reflecting the first full financial year to benefit from the new Northern Gas Pipeline (NGP) and the newly commissioned, high-performing PV13 well at Palm Valley.



Note: Oil converted at 5.816 GJ/bbl.

Sales volumes in the 2nd half of FY2020 were market-constrained due to the significant downturn in spot market conditions, largely reflecting the Company's portfolio of firm long-term gas supply contracts which have various terms that extend into the future as illustrated below.



Sales Revenue

Central recorded record-high sales revenue of $65 million, up 10% on FY2019, and almost double the revenue recognised in FY2018, reflecting the increased field capacity and increased gas volumes sold through the NGP. Realised oil prices were down 31% on FY2019, as a result of global oil price weakness.

Gross Profit

Gross profit from operations increased 9% year on year, benefiting from a 5% drop in unit production costs to $2.71/GJE as increased production levels provided increased economies of scale and strategies to manage costs continued to deliver cost-effective operations.

Other Income

Other income of $8.6 million was received during the year, including $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.

Depreciation and Amortisation

Non-cash depreciation and amortisation costs increased from $12.7 million to $16.3 million, reflecting the increase in production and larger depreciable asset base following the Gas Acceleration Programme (GAP).

An impairment charge of $0.177 million was recognised for legacy costs associated with less-prospective exploration areas.

Net Assets/Liabilities

At 30 June 2020, the Group had a net asset position of $1.6 million, an improvement on FY2019 due to the net profit for the year.

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 $33.8 million. 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.

Debt

Net debt improved by 30% to $46.1 million at 30 June 2020. EBITDAX of $33.4 million covered (2.0x) service of loan facilities of $16.4 million, which included accelerated loan repayments of $11.5 million. This included full repayment of the balance of additional funds previously borrowed for our investment in the GAP. The outstanding balance of the loan facility at 30 June 2020 was $70.8 million, with $7.0 million due for repayment in FY2021.

The consolidated debt ratio at 30 June 2020 improved to 0.45 (2019: 0.49). Debt ratio is defined as: Total Debt/Total Assets. Net gearing at 30 June 2020 was 44% (2019: 40% or 53% if re-based to 30 June 2020 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 2P reserves.

Net Cash Flow

Cash balances increased by $8.1 million over the year. Net cash flow from production operations for 2020 was $29.0 million compared to $31.8 million for 2019 and is net of additional gas purchases of $5.3 million associated with reducing the gas overlift position from the Mereenie joint venture.

After payment of $5.1 million of interest costs, $5.1 million of corporate expenses and $3.1 million for exploration activities, net cash flow from operating activities was $15.7 million, up from $2.5 million in 2019. Exploration expenditure in FY2020 was significantly lower than the $18.1 million outlaid in FY2019 on activities that included the successful Palm Valley 13 exploration well.

The net cash surplus from operating activities was directed towards $11.5 million of borrowing repayments and $3.2 million was invested in sustaining capital works. Cash balances were boosted with the receipt of $7.7 million as final settlement for the transfer of a 50% interest in the Range Gas Project.

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.

	2016 $ MILLION	2017 $ MILLION	2018 $ MILLION	2019 $ MILLION	**2020 $ MILLION**
Financial Data					
Operating revenue	23.86	24.79	34.94	59.36	**65.05**
Exploration expenditure	4.03	1.90	8.79	15.80	**5.28**
Profit/(loss) after income tax	(21.04)	(24.73)	(14.08)	(14.53)	**5.41**
EBITDAX	2.58	2.22	11.01	22.19	**33.40**
Equity issued during year	11.52	—	25.47	—	**—**
Property, plant and equipment	113.78	106.82	103.85	123.48	**107.85**
Cash	15.12	5.48	27.22	17.81	**25.92**
Borrowings	(85.70)	(82.17)	(78.33)	(81.73)	**(70.77)**
Net Assets (Total Equity)	16.52	(5.96)	7.06	(5.62)	**1.58**
Net Working Capital (Net current assets/(liabilities))	5.33	0.73	17.19	(1.53)	**6.75**

	2016	2017	2018	2019	**2020**
Operating Data					
Gas Sales (TJ)	3,230	3,322	4,842	10,229	**11,822**
Oil Sales (barrels)	98,635	111,380	105,619	97,392	**89,016**
No. of employees at 30 June	83	83	89	99	**92**

COMMERCIAL

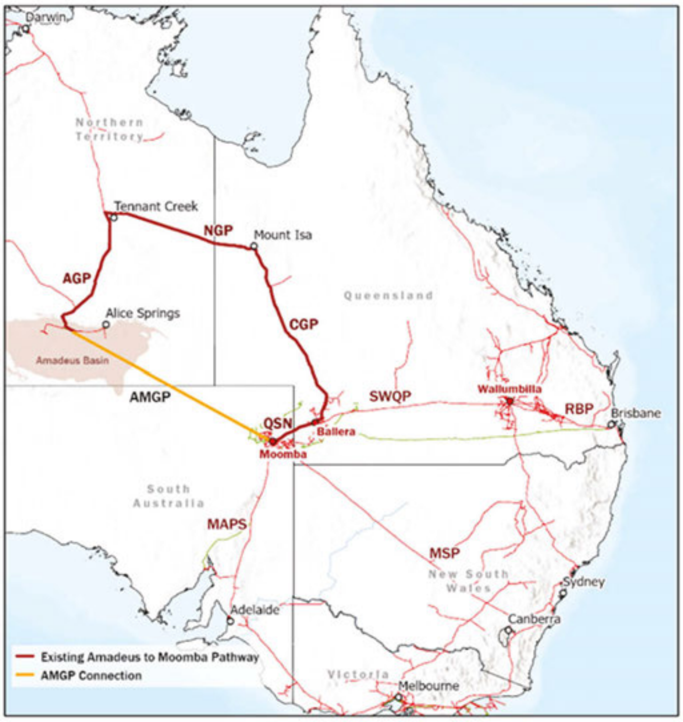
Amadeus to Moomba Gas Pipeline (AMGP)

In August 2020, Central and our partner in the Mereenie gas field, Macquarie Mereenie Pty Ltd, agreed with Australian Gas Infrastructure Group (AGIG) to progress towards a Final Investment Decision (FID) for the development of a proposed major new gas transmission pipeline that would provide direct access from the Amadeus Basin in the Northern Territory (NT) to the Moomba gas supply hub in South Australia (Moomba).

Central currently supplies gas to customers in the NT and Mt Isa. In order for Central to sell gas into the southern parts of the east coast market, gas would be transported over 2,200 km via Mt Isa to Moomba. The proposed AMGP would be less than half that distance, allowing for significantly lower gas transportation costs from the NT to the east coast via a direct pipeline connection to Moomba which is strategically located for supply to Sydney and the south eastern markets.

The AMGP would be developed, owned and operated by AGIG and is planned to be a 950 km pipeline, up to 16-inch in diameter with free-flow capacity of 124 TJ per day (45 PJ per year) and would be expandable with compression.

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 process conducted in 2015. The AMGP project is targeting a FID in 2H of 2021, which could enable commencement of construction in 2022 and deliveries of first gas in Q1 of 2024.



Gas pipeline infrastructure and the proposed Amadeus to Moomba Gas Pipeline (AMGP)

NT Gas Supply

Central's operated fields in the Amadeus Basin have approximately 200PJ of uncontracted conventional gas reserves (gross JV) which can be supplied to market through the AMGP. There are also additional third-party uncontracted conventional gas reserves that could participate as foundation volumes to supply the east coast from 2024.

Central will seek to increase production capacity from our three operated NT gas fields for delivery via the AMGP. The production capacity can be increased by accelerating the drilling of development wells and debottlenecking or expanding existing production facilities at Mereenie, Palm Valley and Dingo.

Aside from already established reserves, Central's planned Amadeus Basin exploration programme to be completed in 2021 is focussed on three high potential gas prospects, aiming to mature 593 PJ of mean prospective gas resources (100% Central). Gas discoveries resulting from this exploration programme, as well as all of Central's future NT exploration activity in the underexplored, but highly prospective Amadeus Basin (such as Dukas), would directly benefit from the AMGP.

In the longer term, the AMGP could directly assist the east coast market by transporting gas from several large discovered offshore gas fields or the various unconventional exploration programmes that are currently underway in the NT. The pipeline could also provide efficient and highly responsive gas storage services to support growing, but intermittent, renewable energy generation.

"The implications of the AMGP project are huge, not just for Central and the NT, but for the entire east coast gas market. The AMGP is strongly aligned with various initiatives to boost east coast gas supply as traditional supplies from Bass Strait and the Cooper Basin decline.

What makes the AMGP stand out above other potential east coast supply proposals, is the pipeline efficiently connects significant known conventional gas reserves from proven producing fields to east coast demand centres from 2024 which are forecast to have gas supply shortages."

Central's CEO and Managing Director, Leon Devaney.

OPERATING AND FINANCIAL REVIEW

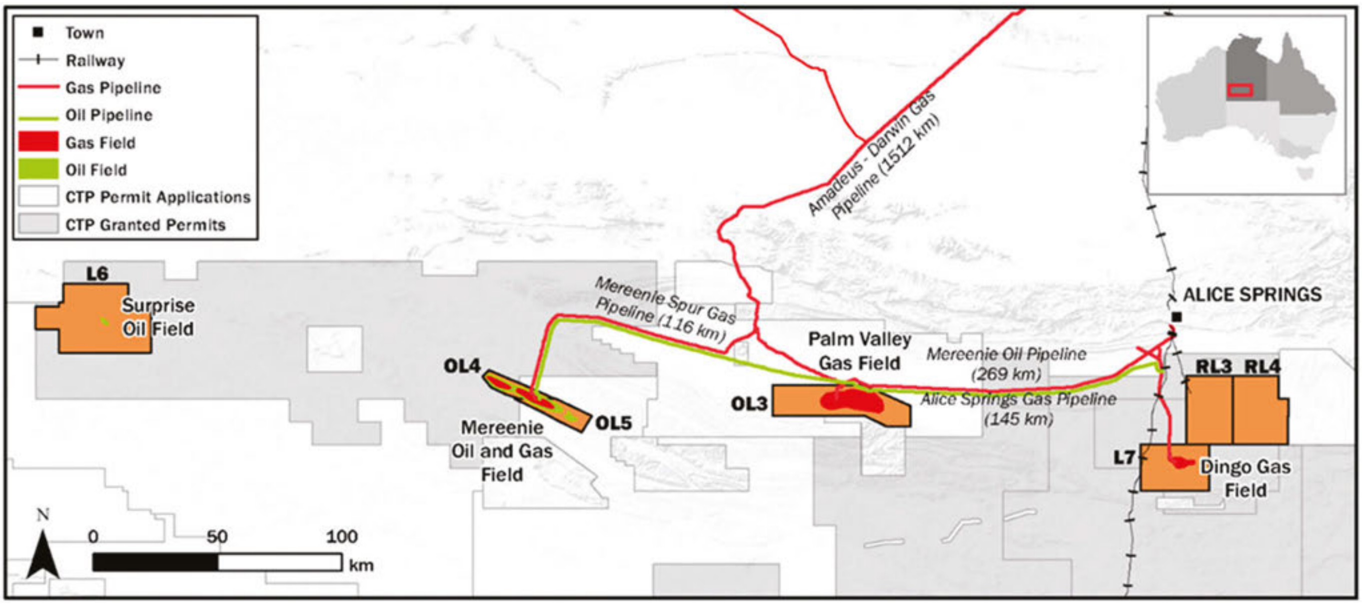
OPERATIONS AND ACTIVITIES

Central Petroleum Limited is the largest onshore gas producer in the Northern Territory (NT), supplying industrial customers and senior gas distributors in NT and the wider Australian east coast market from our three producing fields near Alice Springs.

Central is positioned to become a significant domestic energy supplier, with exploration and development plans across 180,000 km² of tenement and application areas in Queensland and the NT, including some of Australia's largest known onshore conventional gas prospects. 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.

Central is also seeking to develop the Range Gas Project, a new gas field located among proven coal seam gas fields in the Surat Basin, Queensland with 135 PJ (net to Central) of 2C contingent resource.

Producing Assets



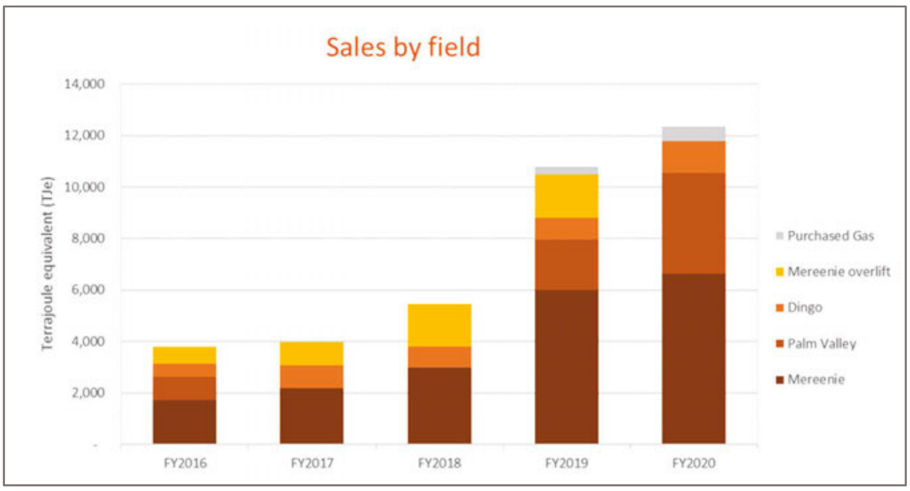
Granted Petroleum Production and Retention Licences in which the Company has an interest

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2020	FY 2019
Gas	PJ	11.8	10.2
Crude and Condensate	bbls	89,016	97,392
Total	**PJE**	**12.3**	**10.8**

Note: Oil is converted to Petajoule equivalent (PJE) at 5.816 GJE/bbl.

Sales volumes were 14% higher than FY2019 at 12.34 PJE, reflecting the first full financial year to benefit from the new Northern Gas Pipeline (NGP) and the newly commissioned, high-performing PV13 well at Palm Valley. Sales volumes in the 2nd half of FY2020 were market-constrained due to the significant downturn in spot market conditions, largely reflecting the Company's portfolio of firm long-term gas supply contracts which have various terms that extend beyond 2025.



Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory

(CTP—50% Interest (Operator), Macquarie Mereenie Pty Ltd—50% Interest)

Sales volumes (Central share)	Unit	FY 2020	FY 2019
Gas	PJ	6.1	7.1
Crude and Condensate	bbl	89,016	97,392

Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	69.3	91.8	91.2
Oil	mmbbl	0.77	0.97	0.10

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 programme 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. Subject to JV approval, a two-well appraisal programme would be the first step in converting up to 54 PJ (Central share) of 2C contingent gas resource to 2P reserves.

Gas production averaged 33 TJ/d over the year. During the first half of FY2020, production averaged 40 TJ/d, impacted by an extended planned outage at the NGP. Gas production was market-constrained at an average 26 TJ/d from January due to weak spot gas markets. Field capacity was approximately 37 TJ/day at 30 June 2020.

Updated reservoir modelling which incorporated recent strong production performance led to a 20% upgrade of the 2P gas reserves at Mereenie, with an additional 15.8 PJ of gas and 0.19 mmbbl of oil (2P reserves, Central share) added at 30 June 2020. The reserve upgrade was a result of a study of technical data from the elevated 2019 production levels which followed the field expansion. The results indicated additional gas is likely to be recovered from lower permeability sands within the Mereenie reservoirs and the sales gas specification can be maintained without the need for additional capital investment to remove Nitrogen.

To offset ongoing natural field decline, a series of minor projects were implemented during the year, including the conversion of several injector wells into production wells.

Additional production capacity is not anticipated to be required to meet the current portfolio of firm gas contracts. Marketing continues for new gas sale contracts and extensive planning has commenced to increase field capacity to meet this anticipated demand, including new development wells and recompletions to access gas which is currently behind pipe in existing wells.

Mereenie Eastern Satellite Station Processing Facilities

Palm Valley Gas Field (OL3)

Northern Territory
(CTP—100% Interest)

Sales volumes (Central share)	Unit	FY 2020	FY 2019
Gas	PJ	3.9	1.9

Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	24.7	27.7	13.7

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 the broader gas market available via the NGP connection.

The Palm Valley field performance exceeded expectations during the year, averaging 10.8 TJ/d, more than double the FY2019 average. The PV13 well, commissioned in May 2019, produced at a consistent 7 TJ/d throughout the year before coming off plateau in June 2020. The continuing 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.

The exceptional performance of the PV13 well led to a 26% upgrade of 2P gas reserves at Palm Valley, adding 5.8 PJ of 2P gas reserves at 30 June 2020.

Palm Valley's existing wells are now experiencing a natural decline in production. 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 maintain a production plateau. It is planned that these laterals will be drilled from existing wells and the proposed PV Deep exploration well with an expectation that future whole-of-life unit production costs at Palm Valley will be significantly reduced.

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

Northern Territory
(CTP—100% Interest)

Sales volumes (Central share)	Unit	FY 2020	FY 2019
Gas	PJ	1.2	0.9

Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	29.3	36.1	—

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 43% higher than FY2019, averaging 3.4 TJ/d with increasing 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 2021 for any gas nomination shortfall by the customer.

Surprise Oil Field (L6)

Northern Territory
(CTP—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 will be considered following a sufficient recovery in oil markets. Environmental and reservoir monitoring continued throughout the year.

Range Gas Project (ATP 2031)

Surat Basin, Queensland
(CTP—50% Interest, Incitec Pivot Queensland Gas Ltd (IPL) – 50%)

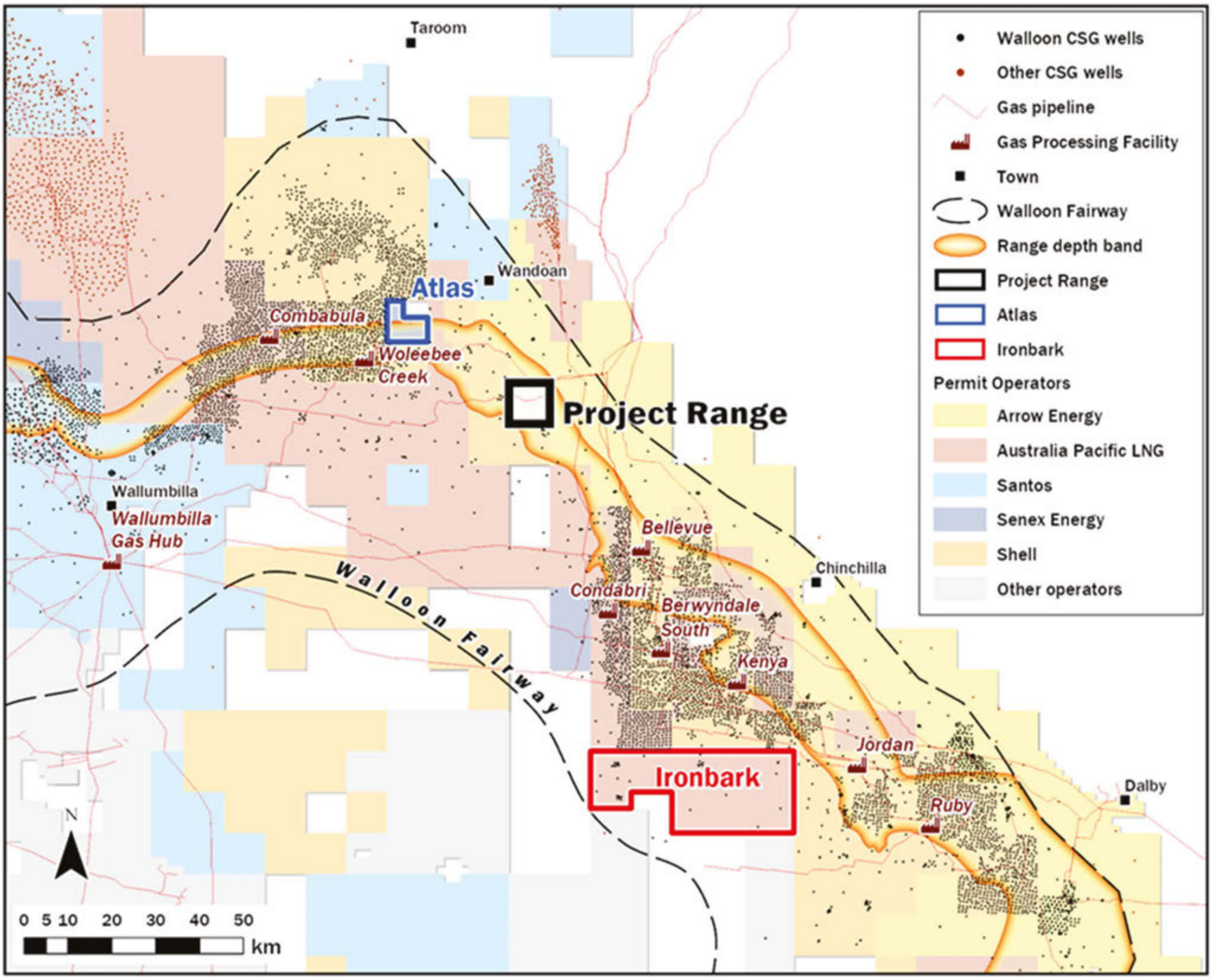
Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	—	—	135

Central was formally granted the Authority to Prospect (ATP) 2031 in Queensland's gas-rich Surat Basin in August 2018. The Range Gas Project's exploration and appraisal programme is being undertaken through a 50:50 joint venture arrangement with IPL. Any gas produced from this permit is to be dedicated to the domestic gas market.

In August 2019, Central booked a maiden 2C contingent gas resource of 270 Petajoules (PJ) (135 PJ Central share) of Coal Seam Gas (CSG) in ATP 2031. 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.

The resources, certified by international certifier NSAI, exceeded expectations and resulted from a successful four-well exploration programme conducted safely, on schedule and on budget during July and August 2019. These wells provided exciting results, demonstrating average coal thickness of 30 metres and drill stem tests indicated that permeability is in line with, or better than, expectations – including the deeper Taroom seams. The excellent permeability and coal thickness suggests that the area should be suitable for gas production from low-cost, un-fracked vertical wells.

Given these excellent results, the joint venture commenced working towards a FID for a substantial CSG development. These pre-FID activities include conducting environmental studies, securing approvals, undertaking engineering studies, selecting equipment and ordering long-lead items. Planning for pre-FID activity, including an appraisal pilot, is well advanced.



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

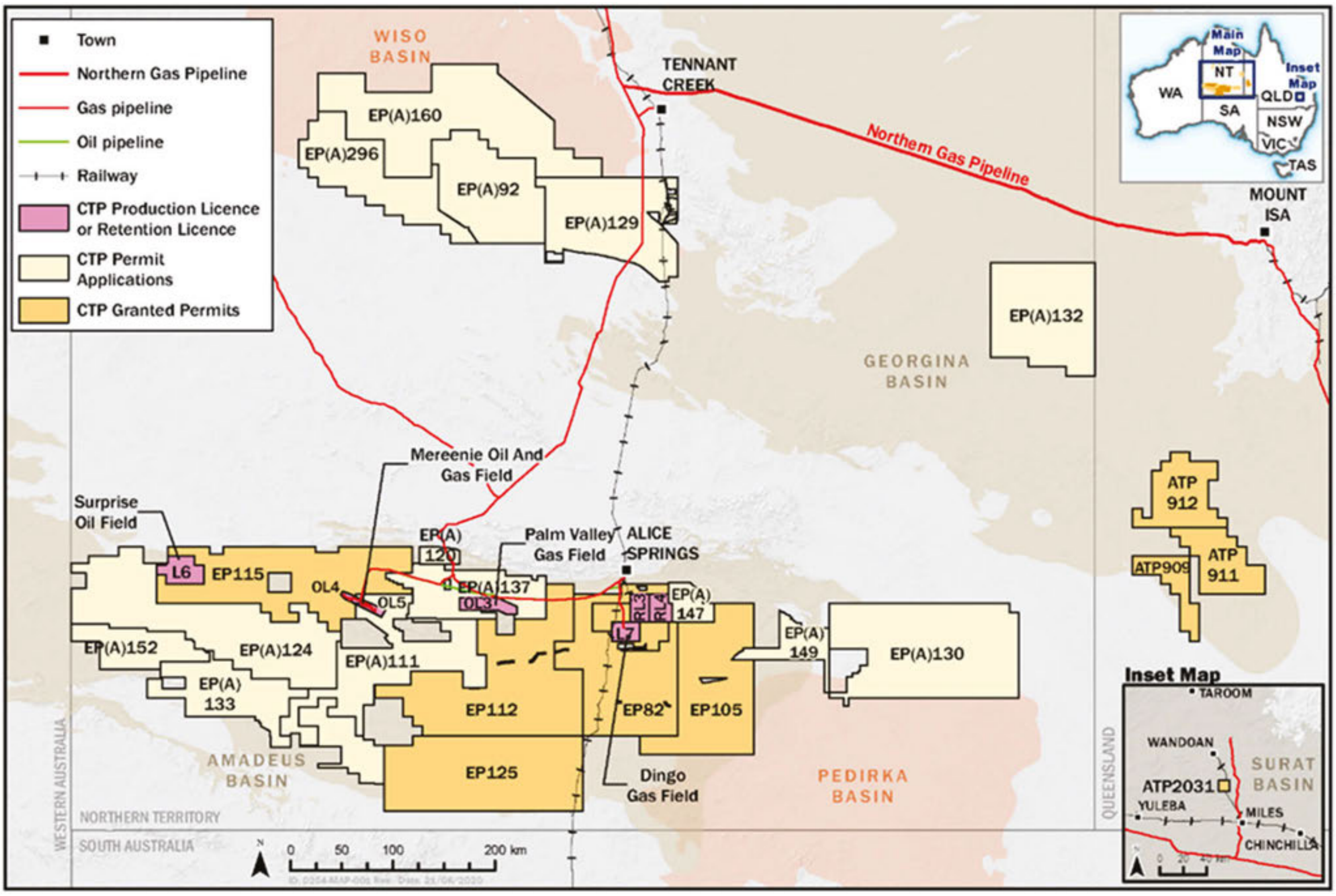
Activity was paused in March 2020 as a prudent fiscal response to business uncertainty associated with the COVID-19 pandemic and the severe gas market downturn. The JV is presently considering opportunities to restart pilot activities and approvals in the 2nd half of CY2020, with FID expected about 12 months after restart.

It is anticipated that finalisation of development plans and a successful appraisal pilot will lead to a conversion of 2C contingent resource to 2P certified reserves. The 2C is currently classified as "development pending", which is the highest category of contingent resource, requiring only satisfaction of FID milestones such as development plans, access to infrastructure and offtake agreements for conversion to certified 2P gas reserves. First gas sales from the Range Gas Project will be targeting an expected shortfall of gas supply in eastern Australia from 2023 onwards.

OPERATING AND FINANCIAL REVIEW

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

Exploration Assets



Granted Petroleum Permits, Licences and Application Interests

The current Central portfolio encompasses opportunities within the Amadeus, Southern Georgina, Wiso and Surat basins. The total area held by Central for exploration (both granted and under application) within these basins is 181,875 km^2 (72,197 km^2 granted and 109,678 km^2 under application).

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 (one oil field currently suspended).

Notwithstanding this 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 can in part be attributed to the small and historically oversupplied Northern Territory gas market which has limited investment in the region.

Following connection to the east coast gas market via the NGP in January 2019, Central's NT exploration assets now have a clear pathway to an attractive east coast gas market. Recognising this new market dynamic, Central has undertaken a full exploration portfolio review, enabling the definition of an attractive exploration drilling campaign targeting lower-risk, higher value targets. In addition, a basin-wide play-based analysis was advanced in order to assess longer term and potentially transformational exploration programmes beyond 2020.

The proposed Amadeus to Moomba Gas Pipeline will, if developed, provide a more direct, efficient route to east coast markets and is likely to provide a catalyst for increased exploration in the Amadeus Basin.

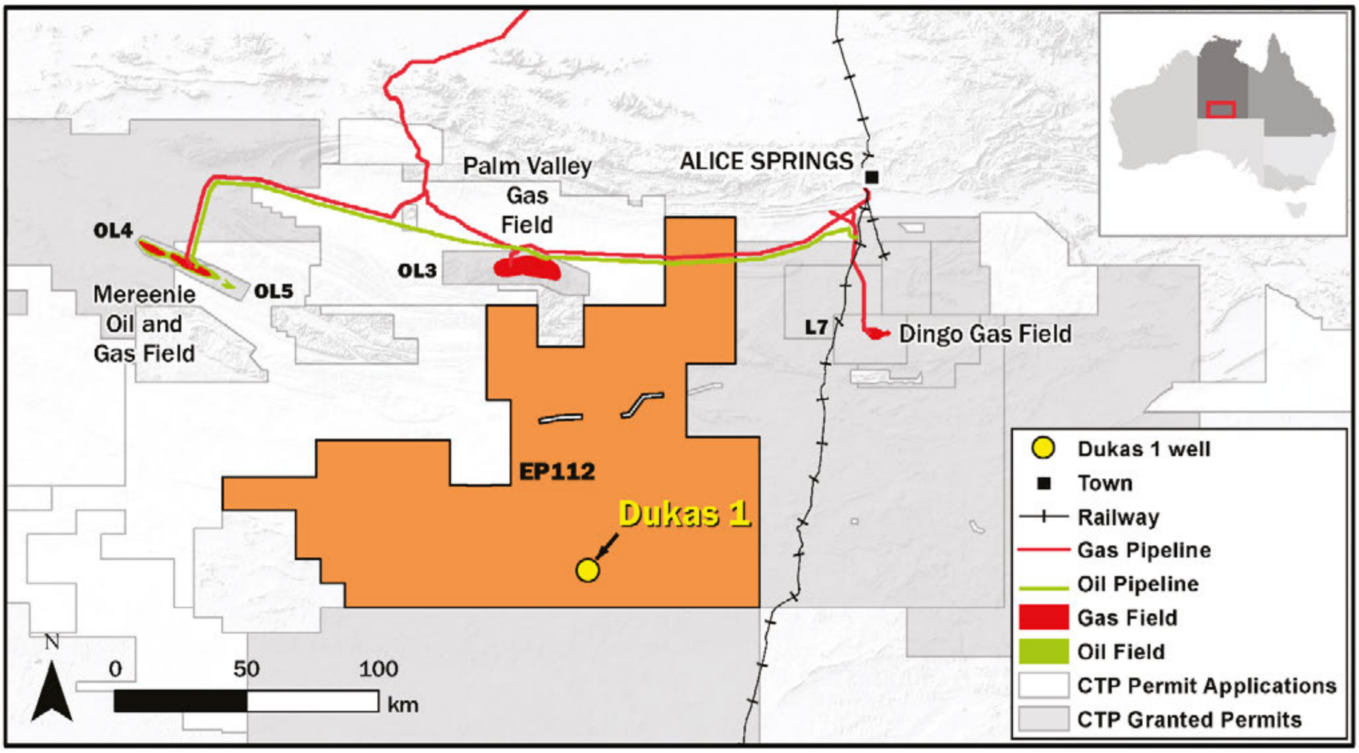
Dukas-1 (EP112)

Southern Amadeus Basin, Northern Territory
(CTP – 30% interest, Santos 70%)

Dukas-1 is located in EP112 approximately 175 km south west of Alice Springs with a possible structural closure in excess of 400 km^2, making it one of the largest known onshore conventional gas prospects in Australia, with multi-Tcf gas potential.

Given the potential size, success at Dukas would be company changing. In addition, several other large 'lookalike" sub-salt closures, such as the Zevon lead in EP115, have been identified from interpretation of earlier seismic data acquired in the Southern Amadeus Basin. As such, success at Dukas-1 has the potential to unlock a significant new hydrocarbon province in the Southern Amadeus Basin and become a major new source of gas for the east coast market.

Dukas-1 was designed to test a large regional high optimally located to receive charge from an interpreted Neoproterozoic depocenter. The primary reservoir objective is the Heavitree Quartzite/fractured basement, a petroleum system which has been proven to be hydrocarbon bearing at Mt. Kitty-1 and McGee-1.



Location map of Dukas-1 and EP112

The Dukas-1 exploration well had a proposed total depth of 3,850m and reached a depth of 3,704m in August 2019 when it encountered formation pressures much higher than predicted in association with a combination of hydrocarbon and inert gasses above the target reservoir formation. Both of these are positive indications for a working petroleum system and effective seal at the Dukas location.

Santos (as operator) subsequently assessed that the technical requirements to continue drilling were in in excess of the capabilities of the rig and surface equipment and drilling activity was suspended and the rig released.

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

Prior to drilling Dukas-1, the JV relied solely on seismic imaging through a thick section of evaporites and complex thrust faulting to map the structure. Specific detail of the structural attitude of the strata overlying the target, however, is now available from recently acquired Dukas-1 well log data and greatly improves structural mapping.

Importantly, the revised structural closure remains very large at greater than 400 km^2, which is comparable in area to multi-Tcf fields such as Bayu-Undan in the Timor Sea. In addition, the revised mapping creates an opportunity to drill a more crestal well, which could increase the potential for a successful outcome.

OPERATING AND FINANCIAL REVIEW

Work is now underway to assess various options to intersect the target formation using specialised high-pressure equipment. The three primary options are:

1. Re-entry of the suspended Dukas-1 well and continue drilling into the formation (limited to operations possible within existing casing sizes);
2. Twinning the existing Dukas-1 well by drilling a new well immediately adjacent to the existing suspended well (using new casing to improve drilling and testing opportunities); or
3. Drilling a new well at a more crestal location.

A decision is expected by late 2020 and the targeted spud timing for the selected option is as soon as possible in 1H of calendar year 2022. This schedule allows the opportunity to consider the various options (including the crestal well), along with the associated well designs, permits and approvals, and sourcing of high-pressure equipment and drill rig.

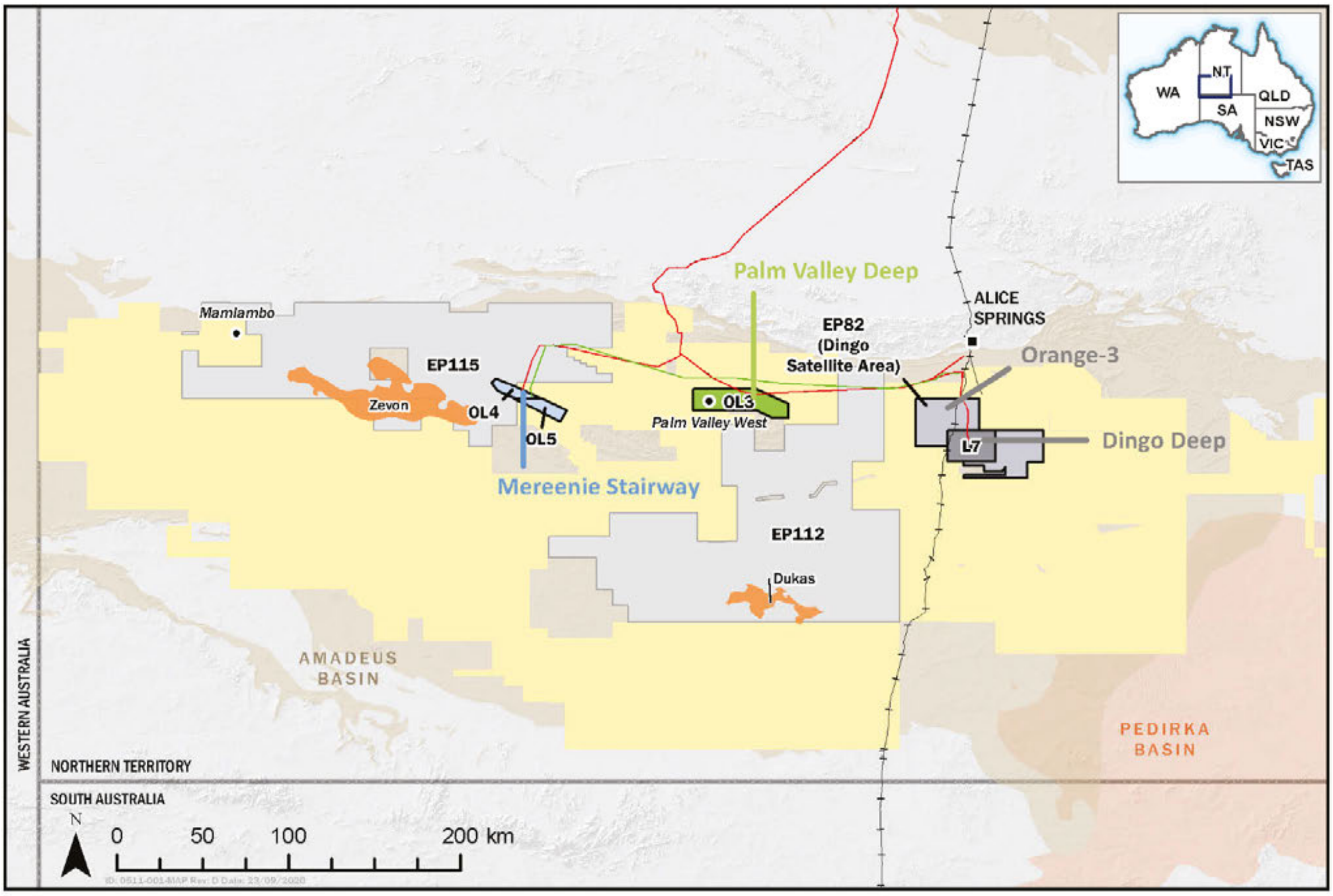
Commercially, Santos can elect for Central to be carried for the first $3 million ($10 million gross JV) of its future Dukas well costs in certain circumstances. In return for a carry by Santos, and if Santos so elects, Central will transfer an additional 30% equity in EP82 to Santos (excluding the Orange prospect in which Central has a 100% interest). This would ensure consistent equity interests across all Central/Santos JV tenures in the middle Southern Amadeus Basin. Santos would also pay to Central certain back-costs associated with the transferred interest for field activities conducted in EP82 from July 2020.

Should Santos not elect to carry Central's expenditure in Dukas in exchange for the option to have 30% equity in EP82, then the equity interest in EP112 (with Dukas-1) will revert from 70% Santos / 30% Central to 55% Santos / 45% Central.

Amadeus Exploration Programme

Southern Amadeus Basin, Northern Territory

In October 2019, a potentially Company-changing exploration programme was announced, consisting of five high-graded drillable targets and two appraisal tests. These exploration targets range from lower to more moderate-risk opportunities with compelling investment justifications, including rapid commercialisation, attractive brownfield economics, proximity to existing infrastructure, and the potential to be quickly implemented. The exploration programme targets natural fractures within conventional formations. No artificial stimulation (hydraulic fracturing) is proposed for this programme.



Location map of priority exploration targets

Work on the exploration programme progressed during the year, finalising well designs and progressing the approval processes required for exploration in the Northern Territory. Permit and environmental management plan applications have been prepared and lodged and well designs are at an advanced stage.

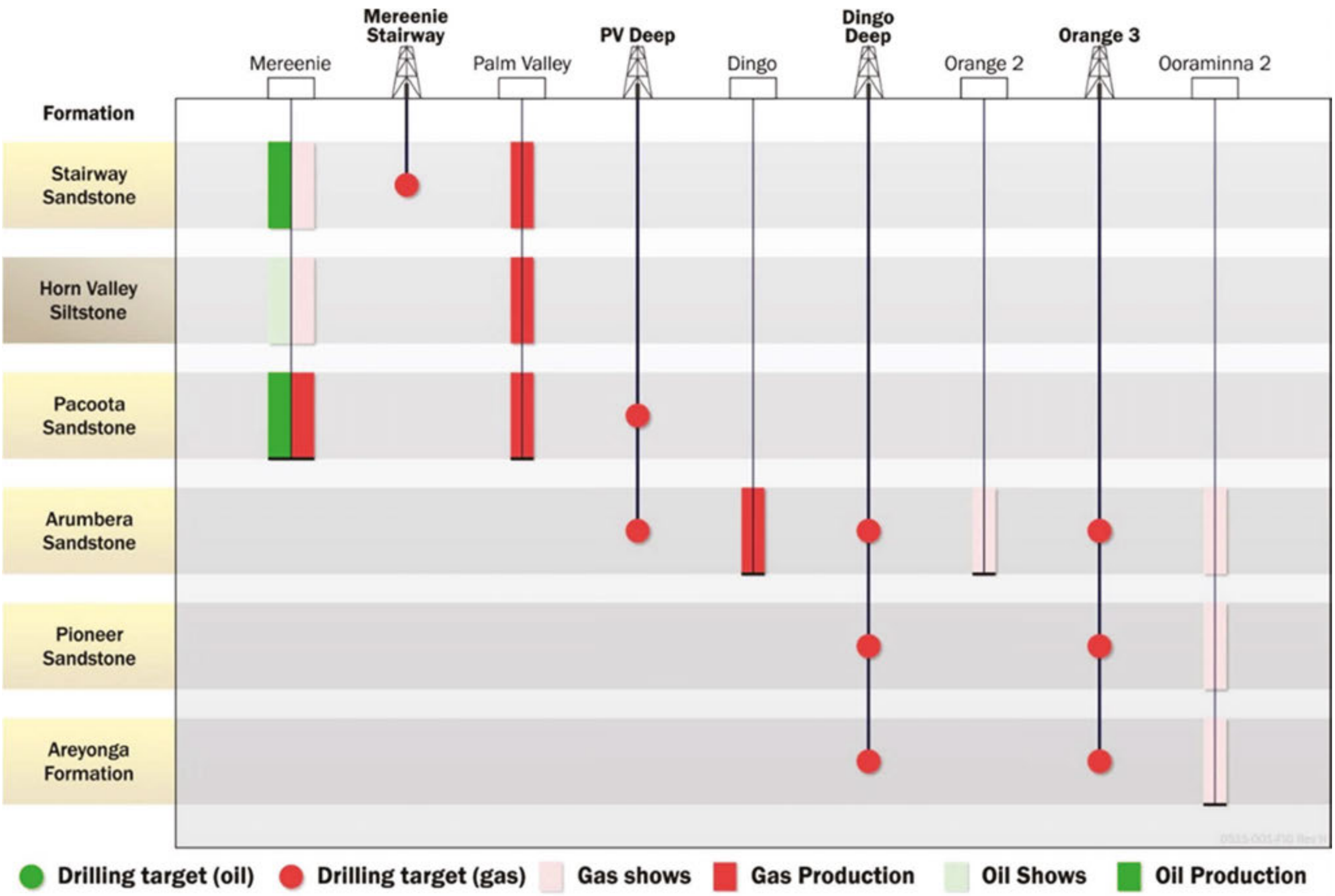
From the original programme, three high potential gas prospects have been prioritised for drilling:

(a) Palm Valley Deep: Deeper reservoir untested within the field (proven at Dingo). Minimal investment would be required in a success case with a potentially large resource. It is planned to sidetrack horizontally into the currently productive Pacoota section for extra production that could be quickly commercialised.

(b) Orange-3 (EP82 DSA): Existing wells have proven hydrocarbons at the shallow Arumbera level (productive zone at Dingo). Additional targets identified in a deeper section of the structure are volumetrically significant and close to the existing Dingo pipeline.

(c) Dingo Deep: The well will be located crestally in the field and provide an additional production well at the currently producing Arumbera level and also explore additional deeper reservoir targets.

In addition, appraisal at the Mereenie Stairway could be undertaken, subject to JV approval. This would require reperforating and testing the Stairway formation from one or more existing wells. This is an undeveloped section of Mereenie with the potential to convert 2C to 2P.



Priority exploration target formations in relation to existing wells

OPERATING AND FINANCIAL REVIEW

The proposed exploration programme will target mean prospective resources, net to Central, of up to 593 PJ of gas (408 PJ best estimate) and, subject to JV approval, 54 PJ of 2C contingent resource.

Prospective Resource[1]		
Lead / Prospect	Best estimate (P50) (PJ)	Mean (PJ)
Dingo Deep	49	**69**
Orange-3	284	**401**
Palm Valley Deep	75	**123**
Aggregate Total	**408**	**593**

2C Contingent Resource[2]	
Appraisal target	(PJ)
Mereenie Stairway	**54**

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.

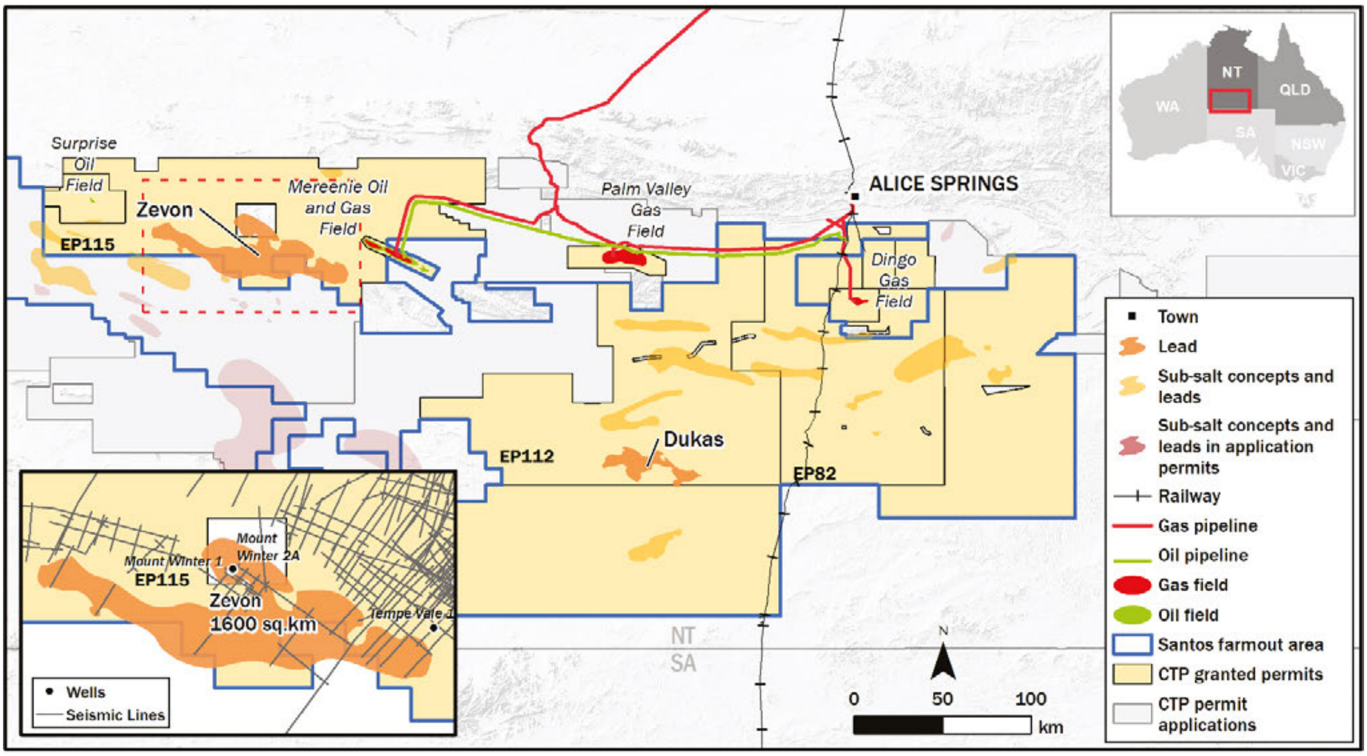
   Cautionary statement: the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.
2. **Contingent Resource**: As first reported to ASX on 13 November 2018.

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.

EP115

Western Amadeus Basin, Northern Territory
(CTP – 100% interest)

EP115 is located in the north-western section of the Amadeus Basin between the Mereenie Oil & Gas Field and the Surprise Oil Field/ Mamlambo oil prospect.



Location of the Zevon lead in EP115

Following the promising indications and technical data derived from the Dukas-1 well, Central is now considering the opportunity to accelerate exploration in EP115 which contains several other large sub-salt targets, such as the Zevon lead which has been defined as a very large closure (circa 1,600 km^2) from seismic and gravity studies.

With the Dukas target drilling window in 1H 2022, Central could use the Dukas rig for drilling in EP115. This would save considerable cost and provide another potentially company-changing exploration well in a permit that is 100% controlled by Central. Planning for a 500 km 2D seismic survey in 2021 is underway to identify a drilling location to enable sharing of the Dukas rig and specialised high-pressure drilling equipment in 2022.

Ooraminna Discovery (RL3 and RL4)

(CTP – 100% interest)

Two wells have been drilled at Ooraminna with both wells having proved gas flow from the Pioneer Formation. Although the flow rates were sub-economic, the wells were drilled in an area with apparent low natural fracture density. Following the portfolio review, the proposed Ooraminna-3 well has been assessed as being less compelling on a risk-return basis than the identified priority exploration targets and will be considered for following programmes after results from the priority programme are analysed.

Southern Amadeus Basin, Northern Territory

Various Exploration Permits (see table on page 105)

The primary exploration objective within these permits is maturing large sub-salt leads in the Neoproterozoic. Potential secondary reservoir objectives are developed within the post-salt units including the Areyonga Formation and Pioneer Sandstone, both of which are gas bearing at the Ooraminna discovery.

In addition to the sub-salt prospects, 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. A full play-based-exploration review is underway with the objective of identifying new plays and fully understanding existing plays.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 105)

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.

Across the Amadeus Basin, further review of the seismic, well, magnetic and recently acquired gravity data was completed, resulting in an inventory of leads and prospects. Play types and leads are also being developed for the under-explored section underlying the proven Ordovician Larapintine system which is believed to be prospective for gas. In the Western Amadeus Basin, a preliminary seismic programme has been designed to target identified structural trends and leads with the aim of defining areas for a follow up infill seismic survey.

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 programme which will form part of the first phase of exploration once tenure is granted.

ATP909, ATP911 and ATP912

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

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

OPERATING AND FINANCIAL REVIEW

RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 161.2 PJE at 30 June 2020, a net increase of 11.4 PJE after accounting for production during the year. Additional 2C contingent gas resources of 135 PJ were recognised for the first time at the Range coal seam gas project in Queensland's Surat Basin after a successful exploration drilling in mid-2019.

Aggregate Reserves and Resources

(Central share)	Unit	As at 30/06/2019	1 July 2019 – 30 June 2020 Production	Adjustments	As at 30/06/2020	Comprising[1] Developed	Undeveloped
Oil							
Proved reserves (1P)	mmbbl	0.68	(0.09)	0.18	**0.77**	0.55	0.22
Proved plus probable reserves (2P)	mmbbl	0.87	(0.09)	0.19	**0.97**	0.83	0.14
Contingent Resources (2C)	mmbbl	0.10	—	—	**0.10**	—	—
Gas							
Proved reserves (1P)	PJ	120.18	(10.64)	13.71	**123.24**	90.28	32.96
Proved plus probable reserves (2P)	PJ	144.69	(10.64)	21.51	**155.56**	124.64	30.92
Contingent Resources (2C)	PJ	104.78	—	135.10	**239.88**	—	—

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

Reserves and Resources by Field

(Central share)	Unit	As at 30/06/2019	1 July 2019 – 30 June 2020 Production	Adjustments	As at 30/06/2020
Mereenie, oil					
Proved reserves (1P)	mmbbl	0.68	(0.09)	0.18	**0.77**
Proved plus probable reserves (2P)	mmbbl	0.87	(0.09)	0.19	**0.97**
Contingent Resources (2C)	mmbbl	0.10	—	—	**0.10**
Mereenie, gas					
Proved reserves (1P)	PJ	71.19	(5.48)	3.54	**69.26**
Proved plus probable reserves (2P)	PJ	81.55	(5.48)	15.76	**91.82**
Contingent Resources (2C)	PJ	91.20	—	—	**91.20**
Palm Valley					
Proved reserves (1P)	PJ	18.49	(3.93)	10.16	**24.73**
Proved plus probable reserves (2P)	PJ	25.83	(3.93)	5.76	**27.66**
Contingent Resources (2C)	PJ	13.58	—	0.10	**13.68**
Dingo					
Proved reserves (1P)	PJ	30.49	(1.23)	—	**29.26**
Proved plus probable reserves (2P)	PJ	37.32	(1.23)	—	**36.08**
Range (Surat Basin, Qld)					
Contingent Resources (2C)	PJ	—	—	135.00	**135.00**

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 and Palm Valley Fields were first reported to ASX on 24 July 2020 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;
- the Dingo Field were first reported to ASX on 24 July 2020 and 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 are as at 15 August 2019, 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 become available. Additionally, external certification is conducted periodically.

RISK MANAGEMENT

Central Petroleum maintains a robust and disciplined focus on effective risk management. We do this so that we better understand uncertainty and manage risks, 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.

Principal risks and uncertainties at 30 June 2020

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
Exploration and Appraisal		
Our future growth depends on our ability to identify, acquire, explore and develop reserves.	Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy.	Exposure to reserve depletion is addressed through our exploration strategy. We continue to analyse existing acreage for exploration drilling prospects and undertake extensive subsurface modelling and uncertainty analysis to determine the most likely production outcomes across our fields. Our disciplined management of opportunities and acquisitions, together with the application of proven technologies and recovery processes, further addresses this risk.
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.

OPERATING AND FINANCIAL REVIEW

Context	Risk	Mitigation
Operating		
Production and delivery of hydrocarbon products to plan 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 programme.
	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 in order to minimise the risk of impacts to operations.
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 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.
Financial		
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 FY2020 which was impacted due to COVID driven market conditions. 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.

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 COIVD-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 have ceased all 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.
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 programme 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.
Information Technology		
We are reliant upon our systems and infrastructure availability and reliability to support the business operating safely and effectively.	The integrity, availability and reliability of data and intellectual property within Central's information technology systems may be subject to intentional or unintentional disruption (e.g. cyber security attack).	Our exposure to cyber security 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 also bolstering our system processes and policy controls.
Human Resources		
We must have the right capability and capacity within our personnel to perform in line with expectations to support our business.	Failure to establish and develop sufficient capability 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.
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 Range coal seam gas project in the Surat Basin aims to begin to geographically diversify our business. We are also investigating other new ventures outside of the Amadeus Basin.

OPERATING AND FINANCIAL REVIEW

Context	Risk	Mitigation
Regulatory Compliance / Change		
Our business activities are subject to extensive regulation and government policy. Our business performance is under-pinned by our licence to operate.	Central is subject to various national and local laws, regulations and approvals, which are subject to change - such as the proposed reserved blocks (no-go zones) for petroleum activities in the Northern Territory. These, along with other changes, could impact the exploration, development, production, transportation and storage of our products and along with it our future prospects.	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 also proactively maintain relationships with governments, regulators and stakeholders within jurisdictions in which we operate.
Climate Change		
We face risks associated with climate change including fluctuations in product demand, carbon pricing and increased stakeholder expectations.	Demand for oil and gas may subside over the longer term 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.	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 as part of a clean energy future compared to other energy sources. Central also seeks value accretive opportunities to reduce carbon emissions.
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.
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, impacting our social licence to operate.	We work in conjunction with our key stakeholders and have established programmes to support and assist the communities in which we operate through donations, sponsorships, local procurement, training and providing ongoing local employment opportunities.
Project Delivery		
Our growth strategy is dependent on our ability to successfully deliver value adding projects.	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.
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.

DIRECTORS' REPORT

FOR THE YEAR ENDED 30 JUNE 2020

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 2020.

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 Stuart Baker

Mr Leon Devaney

Dr Julian Fowles

Mr Wrixon Gasteen

Ms Katherine Hirschfeld AM

Dr Agu Kantsler (appointed 15 June 2020)

Mr Michael (Mick) McCormack (appointed 1 September 2020)

Former Directors:

Mr Martin Kriewaldt (resigned 2 September 2019)

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 (2019: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- Record annual sales volumes and revenues:
    - Volumes up 14% to 12.3 PJE
    - Revenues up 10% to $65 million
- 51% increase in EBITDAX to $33.4 million
- Maiden full year profit of $5.4 million
- 16% increase in 2P reserves to 161.2 PJE
- Added 135 PJ of 2C contingent gas reserves at the Range Gas Project in the Surat Basin after completion of a successful four well exploration programme
- Dukas-1 well was suspended after encountering hydrocarbon-bearing gas from an over-pressured zone close to the primary target and a forward plan to complete the Dukas exploration programme is now underway
- Excellent safety record with no MTIs or LTIs during the year
- Reduced net debt by 30% to $46.1 million and extended loan facility by 12 months to late 2021
- Strengthened the Board with the appointment of Dr Agu Kantsler and Mick McCormack, both highly respected industry leaders with proven experience in the core areas critical to Central's future success
- Subsequent to the year end, announced an MOU with highly capable partners, Macquarie Mereenie and Australian Gas Infrastructure Group (AGIG), to progress towards a FID 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.

A detailed review of the operating and financial performance for the year ended 30 June 2020, including principle risks is provided from pages 3 to 22 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 2020:

- Dukas-1 exploration well was suspended after encountering formation pressures much higher than predicted. Hydrocarbon-bearing gas circulated to surface providing strong evidence of a working petroleum system.
- A four well exploration programme was successfully completed at the Range Gas Project (ATP 2031). Net coal thickness was on prognosis and permeability in line with or better than expected throughout the permit, resulting in the recognition of 135 PJ of 2C contingent resources (Central share).
- Final settlement for the transfer of a 50% interest in the Range Gas Project resulted in a cash receipt of $7.7 million.
- The first full year of access to the Northern Gas Pipeline was reflected in increased sales volumes, up 14% on the preceding year. Revenues increased 10%, impacted by lower oil prices and weak gas markets in the second half of the year.
- Recorded a 16% increase in 2P gas reserves.
- In February 2020 the Macquarie Bank finance facility maturity date was extended by 12 months to 30 September 2021.

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

EVENTS SINCE THE END OF THE FINANCIAL YEAR

Amadeus to Moomba Gas Pipeline

In August, Central announced an agreement to work with Australian Gas Infrastructure Group and Macquarie Mereenie Pty Ltd towards a FID on a proposed new pipeline to enable Central's gas to be transported direct to the Moomba gas supply hub and the larger south-eastern Australian gas markets at a lower cost than existing routes.

Issue of shares

On 18 September 2020, the Company issued 146,215 shares to employee participants in the $1,000.00 Exempt Plan.

Issue and cancellation of share rights

On 18 September 2020, the Company issued 10,179,464 Share Rights pursuant to the Employee Rights Plan. The Company also cancelled 717,033 Share Rights on the same date and a further 211,528 on 23 September 2020.

No other matter or circumstance has arisen between 30 June 2020 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

Central is planning for a period of sustained growth in coming years, targeting a tripling of gas reserves from a new Amadeus exploration programme in 2021 and the Range coal seam gas project in Queensland. Other large, potentially Company-changing exploration prospects, such as Dukas and similar sub-salt leads elsewhere in the Amadeus Basin will also be pursued in coming years. The Group's prospects and leads in the Amadeus Basin are likely to benefit from the proposed new pipeline to the east coast via Moomba, and activities will continue to support the development of this important new route to market.

Further information on these activities is included from pages 1 to 17 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 and 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 Leon Devaney BSc, MBA

Managing Director and Chief Executive Officer

Mr Devaney has 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, as well as the Palm Valley and Dingo Gas Field acquisition from Magellan Petroleum in 2014. 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 Wrixon F Gasteen BE (Mining) (Hons) QLD, MBA (Distinction) Geneva

Independent Non-executive Chairman

Wrix Gasteen has over 30 years' experience in mining, oil and gas, and manufacturing industries in Australia and Asia.

He is an experienced Managing Director and CEO, Executive Director, Independent Non-Executive Director and Chairman of both listed and private companies in Australia, Singapore, Malaysia, and the United States. He is a senior advisor to Australian companies.

He has held senior management positions in the resources industry in Australia. As Chief Mining Engineer, he led the Exploration and Engineering team that discovered and then developed the Boundary Hill Coal Mine in Central Queensland. He became its inaugural Mine Manager.

As Managing Director and CEO of Hong Leong Asia Limited, listed on the Singapore Stock Exchange (SGX: HLA), he transformed and grew the company seven fold, through acquisitions and organic growth, from a loss making company to a highly profitable conglomerate with 14,000 employees, $2.2 billion in sales, 80% of which were in China and SE Asia. Mr Gasteen was also Director of Tasek Corporation (cement) listed on Kuala Lumpur Stock Exchange (KLSE) and Chairman and President of China Yuchai International (diesel engines) listed on the New York Stock Exchange (NYSE).

During his term as Managing Director and CEO of HLA, he was presented with two successive annual awards by the Securities Investors Association of Singapore (SIAS) for Corporate Transparency. The BRW ranked Mr Gasteen No.3 in their Top 20 Australians Managing in Asia.

Mr Gasteen is an Executive Director of Australian dairy milk powder products company, CBS International. He is a Director and co-founder of Ikon Corporate (Singapore), established in 2007 to provide corporate advisory and management consulting services.

Mr Stuart Baker BE(Elec), MBA, AICD

Independent Non-executive Director

Mr Baker was appointed as a Director in December 2018 and has more than four decades of experience in the oil and gas sector and currently provides independent advice to corporates and investors in the Australian oil and gas industry.

Previously he was Executive Director, Morgan Stanley with dual roles as Co-Head Asia Oil, Gas and Chemicals Research and team leader, Australian energy, mining and utility research, 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, and as a Petrophysical Engineer at Schlumberger Inc. based in South-east Asia, rising to General Field Engineer.

Mr Baker is currently a member of the investment committee of resource focused ASX listed Lowell Resources Fund, is a strategic advisor to Karoon Gas Australia Ltd and a Member of the Board of Governors, Shelford Girls Grammar School, Melbourne.

Mr Baker is a member of the Australian Institute of Company Directors and holds a BE(Elec) from the University of Melbourne and an MBA from the Melbourne School of Management.

Dr Julian Fowles PhD, BSc (Hons), GDipAFI, GAICD

Independent Non-executive Director

Dr Fowles was appointed as a Director in June 2019 and is a petroleum industry professional with over 30 years in international leadership roles, including 17 years with Shell International, as well as positions with other major listed companies. He has extensive board, shareholder and analyst engagement experience.

Most recently Dr Fowles was a senior executive with Oil Search limited, leading the PNG operated and non-operated oil and LNG production and development businesses. He was previously the executive leading Oil Search's Exploration and New Business teams and has also been involved in the development and implementation of Oil Search's opportunity development framework, targeting major projects through key assurance processes from pre-concept to FID.

Dr Fowles is a Graduate of the Australian Institute of Company Directors and holds a BSc (Hons) from the University of Edinburgh and a PhD from the University of Cambridge. Dr Fowles also holds a Graduate Diploma in Applied Finance and Investment.

Directorships of other listed companies in the last three years: FAR Limited from 2019.

Ms Katherine Hirschfeld AM BE(Chem) UQ, HonFIEAust, FTSE, FIChemE, CEng, 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 and Tellus Holdings Ltd.

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.

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

Independent Non-executive Director

Mr McCormack was appointed as a Director on 1 September 2020 and has over 35 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, and Director of Austal Limited from September 2020.

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 Committee		Risk Committee		Remuneration & Nominations Committee		Community Affairs Committee	
Director	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Stuart Baker	16	16	4	4	—	3	5	5	—	1
Leon Devaney	16	16	—	3	—	4	—	2	—	2
Julian Fowles	16	15	—	4	4	4	5	5	—	—
Wrixon Gasteen	16	16	4	4	4	4	6	6	2	2
Katherine Hirschfeld AM	16	15	4	4	4	4	—	2	2	2
Agu Kantsler[3]	—	—	—	—	—	—	—	—	—	—
Martin Kriewaldt[4]	3	3	—	—	—	—	—	—	—	—

[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] *Agu Kantsler was appointed 15 June 2020.*
[4] *Martin Kriewaldt resigned 2 September 2019.*

SHARES UNDER OPTION

(a) Options granted during or since the end of the financial year to directors and the five most highly remunerated officers of the Company as part of their remuneration are:

Name of officer	Date granted	Vesting Date	Exercise Price	Expiry Date	Number of options granted
Leon Devaney	7 Nov 2019	30 June 2022	$0.20	30 June 2023	5,105,000
Ross Evans	20 Aug 2019	30 June 2022	$0.20	30 June 2023	4,170,025
Damian Galvin	20 Aug 2019	30 June 2022	$0.20	30 June 2023	2,750,000
Duncan Lockhart	20 Aug 2019	30 June 2022	$0.20	30 June 2023	3,333,333
Robin Polson	20 Aug 2019	30 June 2022	$0.20	30 June 2023	2,792,758

(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. The Directors of the Company and the Consolidated Entity are not aware of any breach of environmental legislation for the year under review.

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 44.

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	
	2020	2019
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	14,657	8,670
R&D Services	—	35,350
Other tax related services	26,092	44,752
	40,749	**88,772**
(ii) Other services		
Consulting services	—	8,865
	—	**8,865**
Total remuneration for non-audit services	**40,749**	**97,637**

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

We started the FY2020 year focused on our next growth phase, building on the strong production base established in FY2019. The global pandemic and related market disruption has resulted in some prudent adjustments to the implementation of our strategy to launch Central into our next phase of growth, but our focus remains on unlocking the full value of our impressive asset portfolio.

Fortunately, we have gathered an experienced Board and management team to guide the Company through the challenging market conditions, and it is important that our remuneration structure provides the right balance of short and long-term incentives to align management with the interests of shareholders.

To keep the remuneration structure relevant in these challenging market conditions, we have made some adjustments across all the components: base remuneration; short term incentives; and long term incentives.

Base remuneration was increased by approximately 2% in July 2019, broadly in line with inflation and following external advice and industry comparison. Given the weak condition of global oil & gas markets through the second half of the year, a Company-wide pay freeze has been implemented for the July 2020 pay reviews.

2020 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 comparator companies (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.

As a result of the market weakness at year end, the LTIP's Absolute TSR performance for the three years from 1 July 2017 to 30 June 2020 failed to achieve the minimum growth hurdle of 10% pa and the Relative TSR placed Central below the 50th percentile compared to its peers, resulting in no 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 2020.

2020 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, departmental and corporate objectives over the year, providing an opportunity to earn up to 10% of base remuneration. Notwithstanding difficult business conditions in CY2020, the Company was successful in achieving safety and cultural heritage KPIs, increasing its 2P oil and gas reserves by 16% and successfully controlling costs. As a result, personnel were entitled to an average 6.97% of their maximum 10% incentive for the year.

After considering the Company's overall performance during the year, cash flow constraints and adverse market conditions caused by the COVID-19 pandemic, the Board decided that Key Management Personnel (KMP) and those managers that report directly to them would receive their STIP entitlement in the form of share rights, which only vest after another 3-years of service.

In addition to preserving cash reserves for growth, this will further align senior management with shareholders and provide a retention incentive as Central embarks on several growth initiatives.

2020 ESOP

Following the approval by shareholders at the Company's 2019 Annual General Meeting, we have introduced an Executive Share Option Plan, replacing the annual LTIP for key executives to more directly align key management objectives with shareholder value. This was in response to shareholder concerns regarding the complexity of the LTIP. The FY2020 grant is in lieu of the LTIP Share Rights which would otherwise be granted over the next three years. The Option exercise price was set at 20 cents, with a 3-year vesting period, and lapse on 30 June 2023.

Consistent with our initiative last year, we have included a Realised Remuneration table (refer Table 1 in section H 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. We will continue to carefully monitor business and market conditions and make the necessary adjustments to appropriately incentivise our dedicated staff to deliver the growth strategies, which will ultimately benefit all shareholders.

Wrixon Gasteen
Remuneration and Nominations Committee Chairman

REMUNERATION REPORT
(AUDITED)

This Remuneration Report for the year ended 30 June 2020 (FY2020) 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
G	Short Term Incentive Plan (STIP)
H	Realised Remuneration
I	Remuneration Details
J	Executive Service Agreements
K	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 Stuart Baker	Non-executive Director
Mr Leon Devaney	Managing Director and Chief Executive Officer
Dr Julian Fowles	Non-executive Director
Mr Wrixon Gasteen	Non-executive Chairman
Ms Katherine Hirschfeld AM	Non-executive Director
Dr Agu Kantsler	Non-executive Director (appointed 15 June 2020)
Mr Michael (Mick) McCormack	Non-executive Director (appointed 1 September 2020)

Former Directors:

Mr Martin Kriewaldt	Non-executive Chairman (resigned 2 September 2019)

Other Key Management Personnel

Mr Ross Evans	Chief Operations Officer
Mr Damian Galvin	Chief Financial Officer (commenced 5 August 2019)
Dr Duncan Lockhart	General Manager Exploration
Mr Robin Polson	Chief Commercial Officer
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 targets and performance against its peers
b. Peer company comparative indicators such as market capitalisation, size, complexity of operations and market developments
c. Adjusting to remuneration best practice
d. Market movements and its impact on the alignment of internal relativities
e. Linking internal strategies for the achievement of improved shareholder value.

B. Remuneration Overview (continued)

Financial Year 2020 Summary of fixed and variable remuneration outcomes	
Salary average increases of 2% at 1 July 2019	Where appropriate, as at 1 July 2019, a pay rise was awarded to address inflation and on account of a change in role, responsibilities or other extenuating circumstances. **A pay freeze has been implemented for the July 2020 pay review, reflecting market conditions.**
STIP	Achievement of Company-wide, departmental and individual KPIs resulted in payment of an average 69.7% of the maximum STIP to eligible employees. **Senior management will receive share rights, instead of cash, with vesting deferred for 3 years.**
LTIP Vesting	The vesting rate for Share Rights issued under the Long Term Incentive Plan for the three year period ending 30 June 2020 was Nil, but may, at the Board's discretion, be eligible for retesting at 31 December 2020. 146,215 shares were issued on 18 September 2020 to participants of the $1,000.00 Exempt Plan.

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 will be the Employee Rights Plan/Long Term Incentive Plan (LTIP) and the Executive Share Option Plan (ESOP) rather than the Short Term Incentive Plan (STIP).

For periods up to and ending on 30 June 2020, 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.

The Board appointed Guerdon Associates to provide remuneration advice to the Board and Remuneration Committee for the July 2019 review. The works undertaken were limited to market reviews of executive remuneration, but the reports received did not include any specific recommendations as to the elements or amounts of Key Management Personnel remuneration.

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.

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

The LTIP is 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 are weighted equally between relative shareholder return and absolute shareholder return. In doing this the Board has identified that it is not sufficient for Central to perform above its peer group for executives to receive their maximum entitlement to share rights but also to achieve levels of absolute share price growth that would be considered as superior returns. For example, for the absolute share price vesting condition to be met, the Central share price must increase by at least 25% per annum for three years, compound growth of 95%.

Key terms and vesting conditions

On 14 November 2018, shareholders re-approved the Company's LTIP 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 over that year compared to a peer group of companies (relative measure) and compared to 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 2020 which will vest (Vesting Percentage) as determined by the performance conditions, based on the 20-day VWAP prior to 30 June 2020 of $0.0882:

Hurdle	Definition	Hurdle Banding	Vesting Percentage	Result for Plan Year Vesting 30 June 2020
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 2020
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%	
		52nd to 75th percentile	51% to 99%	
		51st percentile	50%	
		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 maximum number of unvested Share Rights available for vesting, the Company will calculate the Company's absolute TSR (total shareholder return as measured by an independent company chosen by the Board) and relative TSR effective as at the vesting date in accordance with the above table to determine the relative hurdle band and Vesting Percentage met. The unvested Share Rights for the applicable hurdle for the performance period 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 base salary, their LTIP percentage, 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.

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

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.

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.

This LTIP provides 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 may receive a LTIP percentage up to 50%, subject to shareholder approval; and
    ii) From FY2020 participated in the ESOP;
b. The Executive Management Team (EMT) and eligible employees are those in roles which influence and drive the strategic direction of the Company's business. EMT eligible employees receive a LTIP percentage up to 30%, with certain EMT participating in only the ESOP from FY2020;
c. Eligible employees who are senior managers with responsibility for one or more defined functions, departments or outcomes. They are more likely to be involved in a balance of strategic and operational aspects of management. Some decision-making at this level would require approval from the EMT. These eligible employees receive a LTIP percentage up to 20%;
d. Eligible employees who are not part of the EMT and are in roles which are focused on the key drivers of the operational parts of the Company's business. These eligible employees receive a LTIP percentage up to 10%; and
e. All other eligible employees are integral to the success of the Company obtaining its goals and objectives may participate in the Central Petroleum $1,000.00 Exempt Plan.

Conditions of the Central Petroleum $1,000.00 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.

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

On 9 August 2019, the Board resolved to establish an ESOP for certain key executives, and it was approved by shareholders on 7 November 2019. The ESOP replaces the existing LTIP for participating executives and any Share Options granted under the ESOP will replace the Share Rights that would otherwise have been granted over the next three years under the LTIP. The strike price for each Share Option was set at $0.20 with an expiry date of 30 June 2023.

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 Board may, in its absolute discretion, prescribe service or performance conditions that must be satisfied as a condition for all or any of the Share Options to be exercised.

The exercise price of the Share Options is determined by the Board. 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.

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.

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

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, Departmental and Individual Key Performance Indicators (KPIs) for all eligible employees.

It is the responsibility of the Board to set the strategic direction priorities and objectives of the Company. The existence of this STIP does not amend or take away that responsibility and, as such, the results of the STIP form part of the Board's deliberation in its decision on the bonus recommendation to be awarded.

The Company's Board of Directors determine the maximum amount of STIP achievable in any year (normally expressed as a percentage of base salary). Achieving the maximum is contingent upon all of the KPIs in the matrix being met at the 100% level. The KPIs are reviewed at the beginning of each year and adjusted where necessary to reflect Central's strategic direction, the practice in the marketplace and any other factors which the Board deems relevant. 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. Consistent with the Directors' focus on appreciation in shareholder value as the major form of incentive, STIP payments are currently limited to a maximum of 10% of base salary.

Key terms and conditions

The Financial Year 2020 STIP (FY2020 STIP) has been holistically designed to recognise and reward individual effort through connecting individual KPIs, departmental KPIs and corporate KPIs. These groups of KPIs are intrinsically linked and start by cascading from the corporate KPIs, to the departmental KPIs and then onto individual KPIs. Individual KPIs drive the success of achieving departmental KPIs, which are in turn aimed at effecting the desired outcome to be reached in the corporate KPIs.

Participation in this 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).

	Percent Allocation of STIP	
KPI Category	Executive	All Other Employees
Corporate KPIs	30%	30%
Safety and Environment KPI's	10%	10%
Departmental KPIs	40%	30%
Individual KPIs	20%	30%

Corporate KPIs for FY2020 included:

Objective	Weighting	Performance Outcome for FY2020			
		0%	50%	75%	100%
Exploration Complete exploration portfolio review in order to identify prioritised activities and progress an approved exploration programme	20%			●	
Gas Revenue	20%	●			
Refinancing	20%	●			
Reserve Replacement Reserves adjusted for production	20%				●
Total Cost[1] Total company operating and capital expenditure for agreed scope of works	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 FY2020 included:

Objective	Weighting	Performance Outcome for FY2020			
		0%	50%	75%	100%
Traditional Owner cultural heritage	20%				●
***Safety:** Total Recordable Incident Frequency Rate (TRIFR)	15%				●
Safety: (incident reporting & action close-out)	15%				●
Environment: Recordable environmental incidents	30%		●		
Alice Springs local and Indigenous employment	20%				●

Summary Performance of Company-wide KPI's	Maximum	FY2020 Outcome
Corporate	30% of STI	55% (or 16.5 out of a possible 30)
Safety and Environment	10% of STI	85% (or 8.5 out of a possible 10)
Total	40% of STI	62.5% (or 25 out of a possible 40)

The departmental KPIs vary from one department to the next, however, all are equally important to achieve in the pursuit of achieving 100% of the corporate KPIs which are re-set annually. Departmental KPIs for FY2020 were assessed as achieving 69% on average.

Individual KPIs are linked to the departmental KPIs and as such provide significant relevance to each role in each department and for FY2020 were assessed as achieving an average of 80%.

The FY2020 STIP percentage allocation is a maximum of up to 10% of the employee's Base Salary. Notwithstanding difficult business conditions in CY2020, after assessment of the achievement of the KPIs above, eligible employees were entitled to receive, on average, 69.7% of their maximum STIP bonus.

After considering the Company's overall performance during the year, cash flow constraints and adverse market conditions caused by the COVID-19 pandemic, the Board decided that Key Management Personnel (KMP) and those managers that report directly to them would receive their STIP entitlement in the form of share rights, which only vest after another 3-years of service.

In addition to preserving cash reserves for growth, this will further align senior management with shareholders and provide a retention incentive as Central embarks on several growth initiatives.

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

H. Realised Remuneration

Table 1 identifies the Actual Remuneration received by Senior Executives in respect of the 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 (2020: 8.1 cents per share, 2019: 14 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.

H. Realised Remuneration (continued)

Table 1: Realised Remuneration

	Year	Total Fixed Remuneration[1] $	STI (Cash) $	GAP Bonus (Cash) [2] $	Other Benefits[3] $	STI Vested as Shares[4] $	LTI Vested as Shares[5] $	Total $
Current Executive KMP								
Leon Devaney	**2020**	**612,061**	**—**	**—**	**8,380**	**—**	**—**	**620,441**
	2019	565,939	49,162	41,600	5,159	—	150,917	812,777
Ross Evans	**2020**	**500,404**	**—**	**—**	**8,380**	**—**	**—**	**508,784**
	2019	423,552	20,000	30,000	3,896	20,000	—	497,448
Damian Galvin[6]	**2020**	**289,162**	**—**	**—**	**7,039**	**—**	**—**	**296,201**
	2019	—	—	—	—	—	—	—
Duncan Lockhart[7]	**2020**	**400,472**	**—**	**—**	**8,332**	**—**	**—**	**408,804**
	2019	93,189	—	—	—	—	—	93,189
Robin Polson	**2020**	**335,132**	**—**	**—**	**8,380**	**—**	**—**	**343,512**
	2019	331,400	13,433	24,400	4,293	13,433	—	386,959
Daniel White	**2020**	**444,080**	**—**	**—**	**8,380**	**—**	**—**	**452,460**
	2019	438,064	16,909	—	5,159	16,909	148,401	625,442
Total Executive KMP	**2020**	**2,581,311**	**—**	**—**	**48,891**	**—**	**—**	**2,630,202**
	2019	1,852,144	99,504	96,000	18,507	50,342	299,318	2,415,815

1 *Total Fixed Remuneration includes salaries, fees and superannuation contributions.*
2 *Discretionary bonus in respect of the Gas Acceleration Project.*
3 *Includes car parking and other fringe benefits.*
4 *Short term incentive issued as share rights after year end which vest immediately, valued at cash equivalent STI.*
5 *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.*
6 *Damian Galvin commenced 5 August 2019.*
7 *Duncan Lockhart commenced 8 April 2019.*

I. 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[1] $	Superannuation Contributions $	Termination Benefits $	LSL (Accrued) $	Rights & Options[2] $	Total $	Percent of Remuneration %
Non-Executive Directors										
Stuart Baker[3]	**2020**	**86,250**	—	—	**8,194**	—	—	—	**94,444**	—
	2019	47,139	—	—	4,478	—	—	—	51,617	—
Julian Fowles[4]	**2020**	**81,604**	—	—	**7,752**	—	—	—	**89,356**	—
	2019	—	—	—	—	—	—	—	—	—
Wrixon Gasteen[5]	**2020**	**150,000**	—	—	**14,250**	—	—	—	**164,250**	—
	2019	113,750	—	—	10,806	—	—	—	124,556	—
Katherine Hirschfeld[3]	**2020**	**90,000**	—	—	**8,550**	—	—	—	**98,550**	—
	2019	47,139	—	—	4,478	—	—	—	51,617	—
Agu Kantsler[6]	**2020**	**3,111**	—	—	**296**	—	—	—	**3,407**	—
	2019	—	—	—	—	—	—	—	—	—
Former Non-Executive Directors										
Martin Kriewaldt[7]	**2020**	**26,667**	—	—	**2,533**	—	—	—	**29,200**	—
	2019	167,746	—	—	15,936	—	—	—	183,682	—
Peter Moore[8]	**2020**	—	—	—	—	—	—	—	—	—
	2019	53,333	—	—	5,067	—	—	—	58,400	—
Sarah Ryan[8]	**2020**	—	—	—	—	—	—	—	—	—
	2019	55,417	—	—	5,265	—	—	—	60,682	—
Timothy Woodall[9]	**2020**	—	—	—	—	—	—	—	—	—
	2019	20,000	—	—	1,900	—	—	—	21,900	—
Sub-total	**2020**	**437,632**	—	—	**41,575**	—	—	—	**479,207**	—
	2019	504,524	—	—	47,930	—	—	—	552,454	—
Executives										
Leon Devaney	**2020**	**601,381**	**10,941**	**8,380**	**21,003**	—	**12,688**	**219,916**	**874,309**	**26%**
	2019	551,385	90,762	5,159	22,765	—	20,947	76,358	767,376	22%
Ross Evans	**2020**	**485,955**	**8,945**	**8,380**	**21,003**	—	**6,710**	**176,225**	**707,218**	**26%**
	2019	410,613	70,000	3,896	22,765	—	5,361	23,221	535,856	17%
Damian Galvin[10]	**2020**	**277,551**	**5,363**	**7,039**	**19,779**	—	**2,920**	**99,694**	**412,346**	**25%**
	2019	—	—	—	—	—	—	—	—	N/A
Duncan Lockhart[11]	**2020**	**384,464**	**6,708**	**8,332**	**21,003**	—	**4,073**	**120,841**	**545,421**	**23%**
	2019	94,830	—	—	5,133	—	936	—	100,899	—
Robin Polson	**2020**	**329,546**	**5,446**	**8,380**	**21,003**	—	**4,534**	**120,219**	**489,128**	**26%**
	2019	307,387	51,266	4,293	26,508	—	3,553	17,746	410,753	17%
Daniel White	**2020**	**430,904**	**7,216**	**8,380**	**21,003**	—	**9,180**	**109,385**	**586,068**	**20%**
	2019	418,188	15,918	5,159	24,139	—	9,855	124,249	597,508	23%
Former Executives										
Richard Cottee[12]	**2020**	—	—	—	—	—	—	—	—	**N/A**
	2019	314,975	—	10,105	15,005	52,542	(68,772)	(343,827)	(19,972)	N/A
Michael Herrington[13]	**2020**	—	—	—	—	—	—	—	—	**N/A**
	2019	257,419	—	4,668	15,292	28,366	(53,199)	80,865	333,411	24%
Sub-total	**2020**	**2,509,801**	**44,619**	**48,891**	**124,794**	—	**40,105**	**846,280**	**3,614,490**	**25%**
	2019	2,354,797	227,946	33,280	131,607	80,908	(81,319)	(21,388)	2,725,831	8%
Total Remuneration	**2020**	**2,947,433**	**44,619**	**48,891**	**166,369**	—	**40,105**	**846,280**	**4,093,697**	**22%**
	2019	2,859,321	227,946	33,280	179,537	80,908	(81,319)	(21,388)	3,278,285	6%

I. Remuneration Details – Statutory tables (continued)

Table 2: Remuneration of Directors and Key Management Personnel (continued)

[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 financial year, the Board decided that the 2020 STI is 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. The value shown is based on the fair value as at 30 June 2020 and will be subsequently adjusted to the fair value on the actual grant date. The 2019 STI was subsequently settled partly in cash and partly in equity after year end.*
[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] *Stuart Baker and Katherine Hirschfeld AM were appointed 7 December 2018.*
[4] *Julian Fowles was appointed 28 June 2019.*
[5] *Wrix Gasteen assumed the role of Chairman from 2 September 2019.*
[6] *Agu Kantsler was appointed 15 June 2020.*
[7] *Martin Kriewaldt resigned 2 September 2019.*
[8] *Peter Moore and Sarah Ryan resigned 13 November 2018.*
[9] *Timothy Woodall resigned 29 September 2018.*
[10] *Damian Galvin commenced 5 August 2019.*
[11] *Duncan Lockhart commenced 8 April 2019.*
[12] *Richard Cottee ceased employment effective 31 January 2019.*
[13] *Michael Herrington ceased employment effective 29 January 2019.*

The following factors and assumptions were used in determining the fair value of rights 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
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.*

The following factors and assumptions were used in determining the fair value of share rights granted during FY2019:

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 Sep 2018	22 May 2024	$0.087	Nil	$0.120	86%	2.33%	—
02 Oct 2018[1]	Various	$0.067	Nil	$0.135	N/A	N/A	—
22 Mar 2019[2]	10 Apr 2024	$0.130	Nil	$0.130	N/A	N/A	—

[1] *Adjustment to number of LTIP Rights for plan year commencing 1 July 2015 – valued at the market price of the known vesting %.*
[2] *STIP Rights fully vested on issue – valued at market price on issue.*

Table 3: Short Term Incentives Awarded

		Maximum $	Awarded[1,2] $	Awarded[1] %	Forfeited %
Leon Devaney	**2020**	**61,206**	**43,762**	**71%**	**29%**
	2019	99,547	90,762	91%	9%
Ross Evans	**2020**	**50,040**	**35,779**	**72%**	**28%**
	2019	77,000	70,000	91%	9%
Damian Galvin	**2020**	**33,000**	**21,450**	**65%**	**35%**
	2019	—	—	N/A	N/A
Duncan Lockhart	**2020**	**40,047**	**26,832**	**67%**	**35%**
	2019	—	—	N/A	N/A
Robin Polson	**2020**	**33,513**	**21,784**	**65%**	**35%**
	2019	55,197	51,266	93%	7%
Daniel White	**2020**	**44,408**	**28,865**	**65%**	**35%**
	2019	41,765	33,818	81%	19%
Total	**2020**	**262,214**	**178,472**	**68%**	**32%**
	2019	273,509	245,846	90%	10%

[1] *It was subsequently decided that the FY2020 STIP would be settled in the form of share rights with a further 3-year vesting period. Nil% had vested at 30 June 2020.*
[2] *The FY2019 annual STIP was subsequently settled partly in cash and partly in equity. FY2019 also included a GAP Bonus, as shown in Table 1.*

I. 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
Richard Cottee[1]	**2020**	**—**	**—**	**—**	**—**	**—**
	2019	183,540	02 Oct 18	$0.067	—	09 Feb 21
Leon Devaney	**2020**	**1,837,109**	**07 Nov 19**	**$0.119**	**—**	**12 Nov 24**
	2019	75,089	02 Oct 18	$0.067	—	05 Jan 21
Ross Evans	**2020**	**140,845**	**09 Aug 19**	**$0.142**	**—**	**13-Sep-24**
	2019	778,854	24 Sep 18	$0.087	—	22 May 24
Michael Herrington[2]	**2020**	**—**	**—**	**—**	**—**	**—**
	2019	891,413	24 Sep 18	$0.087	—	22 May 24
	2019	89,187	02 Oct 18	$0.067	—	05 Jan 21
Robin Polson	**2020**	**94,598**	**09 Aug 19**	**$0.142**	**—**	**13-Sep-24**
	2019	603,491	24 Sep 18	$0.087	—	22 May 24
Daniel White	**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**
	2019	804,984	24 Sep 18	$0.087	—	22 May 24
	2019	83,464	22 Mar 19	$0.130	—	10 Apr 24
	2019	73,843	02 Oct 18	$0.067	—	05 Jan 21
Total	**2020**	**3,298,512**				
	2019	3,583,865				

[1] *Richard Cottee ceased employment effective 31 January 2019.*
[2] *Michael Herrington ceased employment effective 29 January 2019.*

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 2Vested[1]	Proportion of LTIP Rights Vested[2]	Proportion of LTIP Rights Forfeited
Richard Cottee[3]	**2020**	**N/A**	**—**	**—**	**—**	**—**	**—**
	2019	2,097,413	01 Jul 15	N/A	1,038,219	49.5%	50.5%
Leon Devaney	**2020**	**1,437,308**	**01 Jul 16**	**N/A**	**1,077,981**	**75.0%**	**25.0%**
	2019	858,089	01 Jul 15	N/A	424,754	49.5%	50.5%
Ross Evans	**2020**	**140,845**	**N/A[5]**	**01 Jul 18**	**140,845**	**N/A[5]**	**N/A[5]**
	2019	—	—	—	—	—	—
Michael Herrington[4]	**2020**	**N/A**	**—**	**—**	**—**	**—**	**—**
	2019	1,019,187	01 Jul 15	N/A	504,497	49.5%	50.5%
Robin Polson	**2020**	**94,598**	**N/A[5]**	**01 Jul 18**	**94,598**	**N/A[5]**	**N/A[5]**
	2019	—	—	—	—	—	—
Daniel White	**2020**	**1,413,345**	**01 Jul 16**	**N/A**	**1,060,008**	**75.0%**	**25.0%**
	2020	**119,077**	**N/A[5]**	**01 Jul 18**	**119,077**	**N/A[5]**	**N/A[5]**
	2019	843,843	01 Jul 15	N/A	417,702	49.5%	50.5%
	2019	83,464	N/A	01 Jul 17	83,464	N/A	N/A
Total	**2020**	**3,205,173**			**2,492,509**	**75.0%**	**25.0%**
	2019	4,901,996			2,468,636	49.5%	50.5%

[1] *The number of rights that vested during the year relates to rights granted in prior financial years under the Long Term Incentive Plan or rights granted in respect of the Short Term Incentive Plan for the year ended 30 June 2019.*
[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. All rights awarded under the Short Term Incentive Plan in respect of the years commencing 1 July 2017 and 1 July 2018 vested on grant date.*
[3] *Richard Cottee ceased employment effective 31 January 2019.*
[4] *Michael Herrington ceased employment effective 29 January 2019.*
[5] *Rights issued as part settlement of FY2019 STIP.*

I. 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	**2020**	**5,105,000**	**07 Nov 19**	**30 Jun 23**	**$0.20**	**$0.087**
	2019	—	—	—	—	—
Ross Evans	**2020**	**4,170,025**	**20 Aug 19**	**30 Jun 23**	**$0.20**	**$0.120**
	2019	—	—	—	—	—
Damian Galvin	**2020**	**2,750,000**	**20 Aug 19**	**30 Jun 23**	**$0.20**	**$0.120**
	2019	—	—	—	—	—
Duncan Lockhart	**2020**	**3,333,333**	**20 Aug 19**	**30 Jun 23**	**$0.20**	**$0.120**
	2019	—	—	—	—	—
Robin Polson	**2020**	**2,792,758**	**20 Aug 19**	**30 Jun 23**	**$0.20**	**$0.120**
	2019	—	—	—	—	—
Total	**2020**	**18,151,116**				
	2019	—				

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 2020	Vesting Date[1]	Maximum value yet to vest[2]			
					FY2020	FY2021	FY2022	FY2023
Leon Devaney	1 Sep 2017	Share Rights – LTIP	754,705	30 Jun 2020	—	—	—	—
	27 Jun 2018	Share Rights – LTIP	135,920	30 Jun 2020	—	—	—	—
	7 Nov 2019	Share Rights – LTIP	1,837,109	30 Jun 2021	—	132,550	—	—
		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	32,822
Ross Evans	24 Sep 2018	Share Rights – LTIP	642,988	30 Jun 2021	—	18,647	—	—
	9 May 2019	Share Rights – LTIP	135,866	30 Jun 2023	—	4,574	—	—
		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	26,834
Damian Galvin		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	16,088
Duncan Lockhart		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	20,124
Robin Polson	24 Sep 2018	Share Rights – LTIP	551,132	30 Jun 2021	—	15,983	—	—
	9 May 2019	Share Rights – LTIP	52,359	30 Jun 2021	—	1,763	—	—
		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	16,338
Daniel White	1 Sep 2017	Share Rights – LTIP	736,319	30 Jun 2020	—	—	—	—
	24 Sep 2018	Share Rights – LTIP	735,145	30 Jun 2021	—	21,319	—	—
	9 May 2019	Share Rights – LTIP	69,839	30 Jun 2021	—	2,351	—	—
	23 Aug 2019	Share Rights – LTIP	983,204	30 Jun 2022	—	—	106,663	—
		Deferred Share Rights – STIP[3]		30 Jun 2023	—	—	—	21,649
Total			**6,634,586**		**—**	**197,187**	**106,663**	**133,855**

[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 will be awarded as rights to deferred shares instead of cash. The grant date and final number of rights are yet to be determined. The maximum value of these rights yet to vest is calculated as the estimated fair value as at 30 June 2020 and will be adjusted to the fair value at the grant date once granted.*

I. 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							
Richard Cottee[1]	**2020**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	6,952,766	183,540	(6,098,087)	—	1,038,219	N/A
Leon Devaney	**2020**	**2,202,158**	**1,837,109**	**(233,552)**	**(1,077,981)**	**N/A**	**2,727,734**
	2019	2,985,158	75,089	(433,335)	(424,754)	N/A	2,202,158
Ross Evans	**2020**	**778,854**	**140,845**	**—**	**(140,845)**	**N/A**	**778,854**
	2019	—	778,854	—	—	N/A	778,854
Michael Herrington[2]	**2020**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	3,380,501	980,600	(1,870,478)	(504,497)	1,986,126	N/A
Robin Polson	**2020**	**603,491**	**94,598**	**—**	**(94,598)**	**N/A**	**603,491**
	2019	—	603,491	—	—	N/A	603,491
Daniel White	**2020**	**2,830,969**	**1,225,960**	**(353,337)**	**(1,179,085)**	**N/A**	**2,524,507**
	2019	2,795,985	962,291	(426,141)	(501,166)	N/A	2,830,969
Total	**2020**	**6,415,472**	**3,298,512**	**(586,889)**	**(2,492,509)**	**—**	**6,634,586**
	2019	16,114,410	3,583,865	(8,828,041)	(1,430,417)	3,024,345	6,415,472

[1] *Richard Cottee ceased employment effective 31 January 2019.*
[2] *Michael Herrington ceased employment effective 29 January 2019.*

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	**2020**	**—**	**5,105,000**	**$0.20**	**30 Jun 23**	**—**	**—**	**N/A**	**5,105,000**
	2019	—	—	—		—	—	N/A	—
Ross Evans	**2020**	**—**	**4,170,025**	**$0.20**	**30 Jun 23**	**—**	**—**	**N/A**	**4,170,025**
	2019	—	—	—		—	—	N/A	—
Damian Galvin	**2020**	**—**	**2,750,000**	**$0.20**	**30 Jun 23**	**—**	**—**	**N/A**	**2,750,000**
	2019	—	—	—		—	—	N/A	—
Duncan Lockhart	**2020**	**—**	**3,333,333**	**$0.20**	**30 Jun 23**	**—**	**—**	**N/A**	**3,333,333**
	2019	—	—	—		—	—	N/A	—
Robin Polson	**2020**	**—**	**2,792,758**	**$0.20**	**30 Jun 23**	**—**	**—**	**N/A**	**2,792,758**
	2019	—	—	—		—	—	N/A	—
Total	**2020**	**—**	**18,151,116**			**—**	**—**	**—**	**18,151,116**
	2019	—	—			—	—	—	—

I. 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
Executive Directors								
Stuart Baker[1]	**2020**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2019	N/A	—	—	—	—	N/A	—
Julian Fowles[2]	**2020**	**—**	**N/A**	**100,000**	**—**	**—**	**N/A**	**100,000**
	2019	N/A	—	—	—	—	N/A	—
Wrixon Gasteen	**2020**	**293,337**	**N/A**	**500,000**	**—**	**—**	**N/A**	**793,337**
	2019	293,337	N/A	—	—	—	N/A	293,337
Katherine Hirschfeld[1]	**2020**	**200,000**	**N/A**	**560,850**	**—**	**—**	**N/A**	**760,850**
	2019	N/A	200,000	—	—	—	N/A	200,000
Agu Kantsler[3]	**2020**	**N/A**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2019	N/A	N/A	—	—	—	N/A	—
Martin Kriewaldt[4]	**2020**	**1,100,000**	**N/A**	**—**	**—**	**—**	**1,100,000**	**N/A**
	2019	1,100,000	N/A	—	—	—	N/A	1,100,000
Peter Moore[5]	**2020**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	265,000	N/A	50,000	—	—	315,000	N/A
Sarah Ryan[5]	**2020**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	105,000	N/A	100,000	—	—	205,000	N/A
Timothy Woodall[6]	**2020**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	1,500,000	N/A	250,000	—	—	1,750,000	N/A
Sub-total	**2020**	**1,593,337**	**—**	**1,160,850**	**—**	**—**	**1,100,000**	**1,654,187**
	2019	3,263,337	200,000	400,000	—	—	2,270,000	1,593,337
Other Key Management Personnel								
Richard Cottee[7]	**2020**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	889,933	N/A	—	—	(47,700)	842,233	N/A
Leon Devaney	**2020**	**1,053,776**	**N/A**	**475,000**	**1,077,981**	**—**	**N/A**	**2,606,757**
	2019	629,022	N/A	—	424,754	—	N/A	1,053,776
Ross Evans	**2020**	**—**	**N/A**	**—**	**140,845**	**—**	**N/A**	**140,845**
	2019	—	N/A	—	—	—	N/A	—
Damian Galvin[8]	**2020**	**N/A**	**71,000**	**70,000**	**—**	**—**	**N/A**	**141,000**
	2019	N/A	N/A	—	—	—	N/A	N/A
Michael Herrington[9]	**2020**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2019	572,564	N/A	—	504,497	—	1,077,061	N/A
Duncan Lockhart[10]	**2020**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2019	N/A	—	—	—	—	N/A	—
Robin Polson	**2020**	**—**	**N/A**	**—**	**94,598**	**—**	**N/A**	**94,598**
	2019	—	N/A	—	—	—	N/A	—
Daniel White	**2020**	**1,129,989**	**N/A**	**—**	**1,179,085**	**—**	**N/A**	**2,309,074**
	2019	628,823	N/A	—	501,166	—	N/A	1,129,989
Sub-total	**2020**	**2,183,765**	**71,000**	**545,000**	**2,492,509**	**—**	**—**	**5,292,274**
	2019	2,720,342	—	—	1,430,417	(47,700)	1,919,294	2,183,765
Total KMP	**2020**	**3,777,102**	**71,000**	**1,705,850**	**2,492,509**	**—**	**1,100,000**	**6,946,461**
	2019	5,983,679	200,000	400,000	1,430,417	(47,700)	4,189,294	3,777,102

[1] *Stuart Baker and Katherine Hirschfeld AM were appointed Directors 7 December 2018.*
[2] *Julian Fowles was appointed Director 28 June 2019.*
[3] *Agu Kantsler was appointed 15 June 2020.*
[4] *Martin Kriewaldt resigned 2 September 2019.*
[5] *Sarah Ryan and Peter Moore resigned 13 November 2018.*
[6] *Timothy Woodall resigned 29 September 2018.*
[7] *Richard Cottee ceased employment effective 31 January 2019.*
[8] *Damian Galvin commenced 5 August 2019.*
[9] *Michael Herrington ceased employment effective 29 January 2019.*
[10] *Duncan Lockhart commenced 8 April 2019.*

J. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity 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	$612,061	6 months
Ross Evans	Chief Operations Officer	01 Dec 2022	$500,403	6 months
Damian Galvin	Chief Financial Officer	05 Aug 2022	$330,000	6 months
Duncan Lockhart	General Manager Exploration	08 Jul 2022	$400,000	6 months
Robin Polson	Chief Commercial Officer	01 Oct 2022	$335,131	6 months
Daniel White	Group General Counsel & Company Secretary	30 Nov 2021	$444,080	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.*

K. 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 FY2020.

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

FY2020 Committee Fees (per annum)		
Audit	Chair	$10,000
	Member	$5,000
Community Affairs	Chair	$10,000
	Member	$5,000
Remuneration & Nominations	Chair	$10,000
	Member	$5,000
Risk	Chair	$10,000
	Member	$5,000

In FY2021, there will be three Committees, with Committee Fees as follows:

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:

Wrixon Gasteen
Chairman

24 September 2020

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2020, 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.

Tim Allman
Partner
PricewaterhouseCoopers

Brisbane
24 September 2020

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FINANCIAL REPORT

CONTENTS

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 review of operations and activities on pages 3 to 22. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 24 September 2020. 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. Press releases, financial reports and other information are available via the links on our website: www.centralpetroleum.com.au.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2020

	NOTE	2020 $'000	2019 $'000
Revenue from contracts with customers – sale of hydrocarbons	2	65,046	59,358
Cost of sales		(33,386)	(30,369)
Gross profit		**31,660**	**28,989**
Other income	3	8,610	385
Exploration expenditure		(5,277)	(15,802)
Employee benefits and associated costs net of recoveries	4(b)	(4,512)	(5,194)
Share based employment benefits	32(d)	(1,937)	(602)
General and administrative expenses net of recoveries		(266)	(1,032)
Depreciation and amortisation	4(a)	(16,257)	(12,695)
Impairment expense	4(c)	(177)	—
Finance costs	4(a)	(6,433)	(8,575)
Profit/(Loss) before income tax		**5,411**	**(14,526)**
Income tax (expense)/credit	5	—	—
Profit/(Loss) for the year		**5,411**	**(14,526)**
Other comprehensive profit/(loss) for the year, net of tax		—	—
Total comprehensive profit/(loss) for the year		**5,411**	**(14,526)**
Total comprehensive profit/(loss) attributable to members of the parent entity		**5,411**	**(14,526)**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic earnings/(loss) per share (cents)	23	**0.75**	**(2.05)**
Diluted earnings/(loss) per share (cents)	23	**0.75**	**(2.05)**

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET

AS AT 30 JUNE 2020

	NOTE	2020 $'000	2019 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	25,918	17,806
Trade and other receivables	8	6,774	9,060
Inventories	9	2,581	2,720
Total current assets		35,273	29,586
Non-current assets			
Property, plant and equipment	10	107,845	123,475
Right of use assets	11	1,059	—
Exploration assets	12	8,722	8,899
Intangible assets	13	312	113
Other financial assets	14	2,656	2,771
Goodwill	15	3,906	3,906
Total non-current assets		124,500	139,164
Total assets		**159,773**	**168,750**
LIABILITIES			
Current liabilities			
Trade and other payables	16	5,287	6,006
Deferred revenue	2(b)	10,891	6,753
Borrowings	17	6,964	10,957
Lease liabilities	11	608	—
Other financial liabilities	18	—	2,025
Provisions	19	4,774	5,376
Total current liabilities		28,524	31,117
Non-current liabilities			
Deferred revenue	2(b)	22,964	15,559
Borrowings	17	63,809	70,773
Lease liabilities	11	618	—
Other financial liabilities	18	—	13,824
Provisions	19	42,276	43,094
Total non-current liabilities		129,667	143,250
Total liabilities		**158,191**	**174,367**
Net assets		**1,582**	**(5,617)**
EQUITY			
Contributed equity	20 (a)	197,776	197,776
Reserves	21	27,238	25,310
Accumulated losses	22	(223,432)	(228,703)
Total equity		**1,582**	**(5,617)**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2020

	Contributed Equity $'000	Reserves $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2018	**197,776**	**23,464**	**(214,177)**	**7,063**
Total loss for the year	—	—	(14,526)	(14,526)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(14,526)	(14,526)
Transactions with owners in their capacity as owners				
Share based payments	—	602	—	602
Options issued for financing	—	1,244	—	1,244
	—	1,846	—	1,846
Balance at 30 June 2019	**197,776**	**25,310**	**(228,703)**	**(5,617)**
Change in accounting policy (Note 1(aa))	—	—	(140)	(140)
Restated total equity as 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**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2020

	NOTE	2020 $'000	2019 $'000
Cash flows from operating activities			
Receipts from customers		62,945	58,924
Interest received		172	373
Other income		6	26
Government grants		(133)	—
Interest and borrowing costs		(5,089)	(6,452)
Payments for exploration expenditure		(3,142)	(18,106)
Payments to other suppliers and employees		(39,032)	(32,300)
Net cash inflow from operating activities	28	15,727	2,465
Cash flows from investing activities			
Payments for property, plant and equipment		(3,224)	(17,481)
Proceeds from sale of property, plant and equipment		76	—
Proceeds and deposits for the disposal of exploration permits		7,713	—
Redemption/(acquisition) of security deposits and bonds		115	2,098
Net cash inflow/(outflow) from investing activities		4,680	(15,383)
Cash flows from financing activities			
Payments for the issue of securities		(10)	—
Proceeds from borrowings and other financing arrangements		—	17,500
Repayment of borrowings	29	(11,501)	(13,999)
Transaction costs related to borrowings		(236)	—
Principal elements of lease payments (2019: Principal elements of finance lease payments)	29	(548)	—
Net cash (outflow)/inflow from financing activities		(12,295)	3,501
Net increase/(decrease) in cash and cash equivalents		**8,112**	**(9,417)**
Cash and cash equivalents at the beginning of the financial year		**17,806**	**27,223**
Cash and cash equivalents at the end of the financial year	7	**25,918**	**17,806**

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 $5,411,000, had a net positive cash flow from operations of $15,727,000 and had an overall net current asset position at 30 June 2020 of $6,749,000. The net current assets include $10,891,000 of deferred revenue 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 2020 of $25,918,000, 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.

Management and the Board are confident that new financing arrangements will be in place before expiry of the existing loan facility in September 2021. If the Company's current process to farm-out (sell-down) an interest in some of its existing assets is successful, it is expected that a significant portion of the proceeds would be available to retire a portion of outstanding debt and reduce the balance maturing in September 2021. The Company is considering various refinancing / maturity extension options.

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 2019 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.

(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:

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

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

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 12.

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). 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 10, 11, 13 and 15.

Other Financial Liabilities

The Group may be required to use assumptions in respect of expected future gas prices in respect of gas sales agreements that contain a financial settlement option. The expected future financial settlements reference expected future gas sales volumes and prices and the terms of individual agreements (refer to Note 18 for further details).

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 farmee. 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 has changed its accounting policy for leases where the Group is lessee. The new policy is described in Note 11(c) and the impact of the change is explained in Note 1(aa).

Until 30 June 2019 all the Group's leases of property, plant and equipment were classified as operating leases (Note 31(c)). Payments made under operating leases (net of any incentives received from the lessor) were charged to profit or loss on a straight-line basis over the period of the lease.

(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 14).

(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 operating 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.

(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

(i) New and Amended Standards Adopted by the Group

In the current period, the Group has adopted all new and revised Standards and Interpretations issued by the Australian Accounting Standards Board that are relevant to its operations and effective for reporting periods beginning on or after 1 July 2019.

(a) AASB 16 Leases

The Group has adopted AASB 16 Leases using the modified retrospective approach from 1 July 2019, and as a result has not restated comparatives for the 2019 reporting period as permitted under the specific transitional provisions in the standard. The reclassifications and adjustments arising from the new leasing rules are therefore recognised in the opening balance sheet on 1 July 2019.

The description of the Group's leasing activities and how they are accounted for is contained in Note 11(c).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations (continued)

(i) New and Amended Standards Adopted by the Group (continued)

The impact of adopting AASB 16 Leases on the Group's financial statements

On adoption of AASB 16, the Group recognised lease liabilities in relation to leases which had previously been classified as 'operating leases' under the principles of AASB117 Leases. These liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate as of 1 July 2019. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on 1 July 2019 was 7.3%. In determining the incremental borrowing rate, the Group was required to make judgements around economic assumptions and specific risks associated with the underlying right-of-use asset.

In applying AASB 16 for the first time, the Group has used the following practical expedients permitted by the standard:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- reliance on previous assessments on whether leases are onerous;
- the accounting for operating leases with a remaining lease term of less than 12 months as at 1 July 2019 as short-term leases
- the exclusion of initial direct costs for the measurement of the right-of-use asset at the date of initial application; and
- the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

The Group has also elected not to reassess whether a contract is or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date the Group relied on its assessment made applying AASB 117 and Interpretation 4 *Determining whether an Arrangement contains a Lease*.

Measurement of lease liabilities

The lease liability recognised at 1 July 2019 is shown below:

	$'000
Operating lease commitments disclosed as at 30 June 2019	1,898
(Less): short-term leases recognised on a straight-line basis as expense	(30)
Gross lease liabilities at 1 July 2019	1,868
Effect of discounting	(253)
Lease liability recognised as at 1 July 2019	**1,615**
Comprising:	
Current lease liabilities	532
Non-current lease liabilities	1,083
	1,615

Measurement of right-of-use assets

The associated right-of-use assets for property leases were measured on a retrospective basis as if the new rules had always been applied. Other right-of use assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognised in the balance sheet as at 30 June 2019. There were no onerous lease contracts that would have required an adjustment to the right-of-use assets at the date of initial application. The recognised right-of-use assets relate to the following types of assets:

	1 July 2019 $'000
Land and buildings	1,030
Plant and equipment	362
Total right-of-use assets	**1,392**

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations (continued)

(i) New and Amended Standards Adopted by the Group (continued)

Adjustments recognised in the balance sheet on 1 July 2019

The change in accounting policy affected the following items in the balance sheet on 1 July 2019:

- right-of-use assets increased by $1,392,000;
- lease liabilities increased by $1,615,000; and
- other financial liabilities decreased by $84,000.

The net impact on accumulated losses on 1 July 2019 was an increase of $140,000.

Impact on segment disclosures and earnings per share

EBITDA, segment assets and segment liabilities for June 2020 all increased as a result of the change in accounting policy. Lease liabilities are now included in segment liabilities, whereas finance leases, if any, were previously excluded from segment liabilities. The following segments were affected by the change in policy:

	EBITDA[1] $'000	Segment Assets $'000	Segment Liabilities $'000
Producing Assets	82	334	344
Unallocated items	568	725	882
	650	**1,059**	**1,226**

[1] *EBITDA is Earnings before Interest, Taxation, Depreciation and Amortisation expense.*

There was no impact on reported earnings per share.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

(a) Revenue from contracts with customers

	2020 $'000	2019 $'000
Sale of hydrocarbon products - point in time		
Natural gas	58,960	49,658
Crude oil and condensate	6,086	9,700
Total revenue from contracts with customers	**65,046**	**59,358**

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

(b) Contract Liabilities

	2020 Current $'000	2020 Non-current $'000	2020 Total $'000	2019 Current $'000	2019 Non-current $'000	2019 Total $'000
Deferred Revenue – take-or-pay contracts[1]	2,714	18,977	21,691	2,715	15,559	18,274
Deferred Revenue – other gas sales contracts[2]	8,177	3,987	12,164	4,038	—	4,038
Total contract liabilities	**10,891**	**22,964**	**33,855**	**6,753**	**15,559**	**22,312**

2. REVENUE FROM CONTRACTS WITH CUSTOMERS (CONTINUED)

(b) Contract Liabilities (continued)

Movements in contract liabilities	Deferred Revenue from Take-or-Pay Contracts $'000	Deferred Revenue from Other Contracts $'000	Total $'000
Carrying amount at 1 July 2019	18,274	4,038	22,312
Revenue recognised from the delivery of gas[3]	—	(7,693)	(7,693)
Gas paid for but not taken during the year	3,417	—	3,417
Amounts transferred from Other Financial Liabilities[4]	—	15,819	15,819
Total contract liabilities	**21,691**	**12,164**	**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.*

[3] *There were no cash inflows during the period associated with the delivery of this gas as the Group received up-front payment for the gas in 2016.*

[4] *In July 2019, Macquarie Bank Limited novated its rights and obligations under the Second and Third Contract Years of the MBL Gas Sale and Prepayment Agreement, to another party who will take physical delivery of the gas. As there is no cash settlement option under the novation agreement, there is no longer a financial liability, and as a result, $15,819,000 previously recognised as Other Financial Liabilities has been transferred to Deferred Revenue. Classification of current and non-current Deferred Revenue is based on the contractual rights of the customer to take gas in each contract year. Revenue is recognised as gas is delivered under the new Gas Sale Agreement.*

3. OTHER INCOME

	2020 $'000	2019 $'000
Interest	152	360
Profit on disposal of exploration permits (a)	8,393	—
Profit on disposal of inventory and other assets	60	—
Other income	5	25
Total other income	**8,610**	**385**

(a) In January 2020 the Consolidated Entity received a Sole Funding Commitment Termination Fee of $7,713,000 (2019: Nil) from its joint venture partner in ATP 2031. 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 (2019: Nil) 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) Loss before income tax includes the following specific expenses

	NOTE	2020 $'000	2019 $'000
Depreciation			
Buildings	10	350	350
Producing assets	10	9,945	7,851
Plant and equipment	10	5,353	4,395
Leasehold improvements	10	40	40
Right of use assets	11	492	—
Total depreciation		**16,180**	**12,636**
Amortisation			
Software	13	77	59
Rental expense relating to operating leases not recognised on the Balance Sheet – Minimum lease payments	11(b)	39	736
Impairment expense	4(c)	177	—
Finance costs			
Interest and fees on debt facilities		5,191	6,466
Interest on lease liabilities	11(b)	102	—
Interest on other financial liabilities		56	650
Revaluation of financial liabilities		(2)	(164)
Amortisation of deferred finance costs		575	1,133
Accretion charge		511	490
Total finance costs		**6,433**	**8,575**

(b) Government Grants

In response to the impacts of COVID-19 the Australian Government has made the JobKeeper support package to eligible affected businesses. The Company recognised subsidies totalling $759,000 (2019: Nil) against employee costs.

(c) Impairment of Exploration Assets

The Consolidated Entity fully impaired the assets relating to exploration tenement EP105 and application area EP(A)130 amounting to $177,000 (2019: Nil). 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.

	2020 $'000	2019 $'000
(a) Income tax expense		
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**
(b) Numerical reconciliation of income tax expense and prima facie tax benefit		
Profit/(Loss) before income tax expense	5,411	(14,526)
Prima facie tax (expense)/benefit at 30% (2019: 30%)	(1,623)	4,358
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(180)	(342)
Share based payments	(581)	(181)
Other items	(8)	(1)
Sub-total	(2,392)	3,834
Deferred tax assets not recognised	—	(3,834)
Recognition of previously unrecognised deferred tax assets	2,392	—
Income tax expense	**—**	**—**
(c) Amounts recognised directly in equity		
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	45	—
Deferred tax assets not recognised	(45)	—
Net amounts recognised directly in equity	**—**	**—**
(d) Tax Losses		
Unutilised tax losses for which no deferred tax asset has been recognised	126,635	127,225
Potential tax benefit at 30%	**37,991**	**38,167**

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

	2020 $'000	2019 $'000
Deferred tax assets		
Provisions and accruals	14,171	14,644
Financial liabilities	—	2,384
Deferred revenue	1,845	610
Other expenditure	425	569
Borrowing costs	56	38
Unutilised losses	52,267	52,621
Total deferred tax assets before set-offs	68,764	70,866
Set-off of deferred tax liabilities pursuant to set-off provisions	(14,276)	(14,454)
Net deferred tax assets not recognised	**54,488**	**56,412**
Movements in deferred tax assets		
Opening balance at 1 July	14,454	13,916
(Charged) / Credited to the income statement	(178)	538
Closing balance at 30 June	**14,276**	**14,454**
Deferred tax assets to be recovered after more than 12-months	11,299	11,556
Deferred tax assets to be recovered within 12-months	2,977	2,898
	14,276	**14,454**
Deferred tax liabilities		
Accrued income	3	11
Capitalised exploration	2,503	476
Property, plant and equipment	11,770	13,967
Total deferred tax liabilities before set-offs	14,276	14,454
Set-off of deferred tax assets pursuant to set-off provisions	(14,276)	(14,454)
Net deferred tax liabilities	**—**	**—**
Movements in deferred tax liabilities		
Opening balance at 1 July	14,454	13,916
(Credited) / Charged to the income statement	(178)	538
Closing balance at 30 June	**14,276**	**14,454**
Deferred tax liabilities to be recovered after more than 12-months	14,097	14,443
Deferred tax liabilities to be recovered within 12-months	179	11
	14,276	**14,454**

6. REMUNERATION OF AUDITORS

	2020 $	2019 $
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	198,578	219,920
Audit of separate subsidiary financial statements	—	43,430
	198,578	263,350
(ii) Taxation services		
Income Tax compliance	14,657	8,670
R&D Services	—	35,350
Other tax related services	26,092	44,752
	40,749	88,772
(iii) Other services		
Consulting services	—	8,865
	—	8,865
Total remuneration of PwC	**239,327**	**360,987**

7. CASH AND CASH EQUIVALENTS

	2020 $	2019 $
Cash at bank and in hand	**25,918**	**17,806**
Made up as follows:		
Corporate (a)	25,252	17,296
Joint arrangements (b)	666	510
	25,918	**17,806**

(a) $5,486,000 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2019: $3,085,000), 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 interest rate risk is discussed in Note 33(c). The maximum exposure to credit risk at the end of the reporting period is the carrying amount of cash and cash equivalents.

8. TRADE AND OTHER RECEIVABLES

	2020 $'000	2019 $'000
Current		
Trade receivables	476	372
Accrued income (a)	4,698	7,427
Other receivables	279	31
Prepayments	1,321	1,230
	6,774	**9,060**

(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

	2020 $'000	2019 $'000
Crude oil and natural gas	61	108
Spare parts and consumables	1,975	1,870
Drilling materials and supplies at cost	545	742
	2,581	**2,720**

10. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2019				
Opening net book amount	2,879	72,831	28,143	103,853
Additions	—	—	16,188	16,188
Changes to rehabilitation estimates	—	16,066	6	16,072
Disposals and write offs	—	—	(2)	(2)
Depreciation charge	(350)	(7,851)	(4,435)	(12,636)
Closing net book amount	**2,529**	**81,046**	**39,900**	**123,475**
At 30 June 2019				
Cost	3,869	100,889	65,546	170,304
Accumulated depreciation	(1,340)	(19,843)	(25,646)	(46,829)
Net book amount	**2,529**	**81,046**	**39,900**	**123,475**
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**

11. LEASES

(a) Amounts recognised in the balance sheet

The balance sheet shows the following amounts relating to leases:

	2020 $'000	2019 $'000
Right-of-use assets		
Land & Buildings	673	—
Plant & Equipment	386	—
	1,059	**—**
Lease Liabilities		
Current	608	—
Non-current	618	—
	1,226	**—**

11. LEASES (CONTINUED)

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

In the previous year, the Group only recognised lease assets and lease liabilities in relation to leases that were classified as 'finance leases' under AASB 117 Leases. Refer to Note 1(aa) for more information on the impact of the change in accounting policy.

Additions to the right-of-use assets during the 2020 financial year were $159,000.

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

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

	2020 $'000	2019 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	359	—
Plant & Equipment	133	—
Total depreciation of right-of-use assets	**492**	**—**
Interest expense	102	—
Expense related to short term leases included in cost of sales and general and administrative expenses	39	—

The total cash outflow for leases in 2020 was $650,000.

(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, but 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.

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.

Until the 2019 financial year, all of the Group's leases of property, plant and equipment were classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) were charged to profit or loss on a straight-line basis over the period of the lease. From 1 July 2019, 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.

11. LEASES (CONTINUED)

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

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.

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.

12. EXPLORATION ASSETS

	2020 $'000	2019 $'000
Acquisition costs of right to explore	**8,722**	**8,899**
Movement for the year:		
Balance at the beginning of the year	8,899	8,899
Impairment expense (Note 4(c))	(177)	—
Balance at the end of the year	**8,722**	**8,899**

13. INTANGIBLE ASSETS

	2020 $'000	2019 $'000
Software		
At the beginning of the year		
Cost	512	495
Accumulated amortisation	(399)	(339)
Net book value	**113**	**156**
Movements for the year		
Opening net book amount	113	156
Additions	276	16
Amortisation	(77)	(59)
Closing net book amount	**312**	**113**
At the end of the year		
Cost	788	512
Accumulated amortisation	(476)	(399)
Net book value	**312**	**113**

14. OTHER FINANCIAL ASSETS

	2020	2019
Non-Current		
Security bonds on exploration permits and rental properties	**2,656**	**2,771**

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.

15. GOODWILL

	2020 $'000	2019 $'000
Goodwill arising from business combinations	**3,906**	**3,906**

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.

In determining impairment indicators, an assessment of the fair value less cost of disposal is made by estimating future cash flows from available 2P reserves over a 20-year period from balance date, being the period over which the value of existing reserves is expected to be substantially realised. Cash flows include estimated capital expenditure to enhance production. The future cash flows are discounted to their present value using a post-tax discount rate, which includes an assessment of asset specific risks and the time value of money. The calculations require significant management judgement and are subject to risk and uncertainty, and broader economic conditions.

The impacts of COVID-19 are forecast to continue to affect short term demand and this has been factored into estimated future cash flows. The following table sets out the key assumptions used in assessing the fair value less cost to sell of producing assets:

2020	Producing Assets
Sales volumes	2P Reserves
Sales price (% annual growth rate)	2 - 2.5%
Operating costs (% annual growth rate)	2 - 2.5%
Post-tax discount rate (%)	11.00%

15. GOODWILL (CONTINUED)

Management has determined the values assigned to each of the above key assumptions as follows:

Assumption	Approach used to determine values
Sales volume	Natural gas sales are based on both Annual Contract Quantities for existing contracts which continue at projected nominations and uncontracted volumes taking into account firm plant capacity, and subject to 2P reserves. Crude and condensate volumes are based on projected field production, taking into account historical production and forecast reservoir decline.
Sales price	Existing contracts are based on current contracted prices escalated for CPI increases as per the contract terms. Some contracts contain minimum and maximum increases. Uncontracted gas sales are based on estimated attainable gas prices taking into account indicative customer proposals. Crude and condensate pricing is based on a mid-point of independent analyst forecasts of crude prices and a long-term forecast average USD exchange rate. The Group' s oil and gas price forecasts take into account any expected impact of climate change, potential policy responses and other factors that may impact longer term forecasts.
Operating costs	Current budgeted operating costs which are based on past performance and expectations for the future. Forecasts are inflated beyond the budget year using inflationary estimates. Other known factors are included where applicable and known with certainty.
Capital expenditure	Expected cash costs where further field capital expenditure is required in order to meet contracted and projected sales volumes.
Annual growth rate	This is the average growth rate used to extrapolate cash flows beyond the budget period. Management considers forecast inflation rates and industry trends if applicable.
Post-tax discount rate	This rate reflects risks relating to the segment. Post-tax discount rates have been applied to discount the forecast future post-tax cash flows.

16. TRADE AND OTHER PAYABLES

	2020 $'000	2019 $'000
Current		
Trade payables	2,026	2,079
Other payables	11	40
Tax related payables	—	634
Deposits held	—	150
Accruals	3,250	3,103
	5,287	**6,006**

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.

17. BORROWINGS

	2020 $'000	2019 $'000
(a) Current[1]		
Debt facilities	6,964	10,957
	6,964	**10,957**
(b) Non-current[1]		
Debt facilities	63,809	70,773
	63,809	**70,773**

[1] *Details regarding interest bearing liabilities are contained in Note 33(e).*

18. OTHER FINANCIAL LIABILITIES

	2020 $'000	2019 $'000
Current		
Lease incentive liabilities	—	39
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	—	1,986
	—	**2,025**
Non-Current		
Lease incentive liabilities	—	45
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	—	13,779
	—	**13,824**

(a) The balance at 30 June 2019 represents the remaining liabilities under the Second and Third Contract Year of the MBL Gas Sale and Prepayment Agreement where Macquarie Bank Limited had an option to receive a financial settlement in lieu of physical gas delivery. In July 2019 Macquarie Bank Limited novated its rights and obligations under those remaining contract years to a third party. This resulted in an amount of $15,819,000 being reclassified from Other Financial Liabilities to Deferred Revenue (Note 2(b)).

19. PROVISIONS

	2020			2019		
	Current $'000	Non-Current $'000	Total $'000	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	3,942	828	4,770	3,530	763	4,293
Restoration and rehabilitation (b)	120	37,988	38,108	529	38,323	38,852
Other:						
Joint Venture production over-lift (c)	712	3,460	4,172	—	4,008	4,008
Other provisions (d)	—	—	—	1,317	—	1,317
	4,774	**42,276**	**47,050**	**5,376**	**43,094**	**48,470**

(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 $788,000 (2019: $739,000).

(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.

(d) Other Provisions comprises provisions for liquidated damages under gas sales agreements and settlement of legal matters (both nil at 30 June 2020).

19. PROVISIONS (CONTINUED)

Movements in Provisions

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

2020	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Other $'000	Total $'000
Carrying amount at start of year	4,293	38,852	4,008	1,317	48,470
Change in provision charged to property, plant and equipment	—	(2,774)	—	—	(2,774)
Additional provisions charged to profit or loss	2,975	1,527	733	22	5,257
Unwinding of discount	—	511	—	—	511
Amounts used during the year	(2,498)	(8)	(569)	(1,339)	(4,414)
Carrying amount at end of year	**4,770**	**38,108**	**4,172**	**—**	**47,050**

20. CONTRIBUTED EQUITY

(a) Share capital

	2020 $'000	2019 $'000
723,288,869 fully paid ordinary shares (2019: 713,355,716)	**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

	2020 Number of Shares	2019 Number of Shares	2020 $'000	2019 $'000
Balance at start of year	713,355,716	707,115,793	197,776	197,776
Shares issued under Employee Incentive Plans	9,933,153	6,239,923	—	—
Balance at end of year	**723,288,869**	**713,355,716**	**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
Unlisted financing options	01 Sep 2019	$0.194	30,000,000	—	(30,000,000)	—	—
Unlisted financing options	31 Dec 2019	$0.140	22,500,000	—	(22,500,000)	—	—
Total			**52,500,000**	**18,151,116**	**(52,500,000)**	**—**	**18,151,116**

20. CONTRIBUTED EQUITY (CONTINUED)

(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.

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	9,577,506	618,276	(3,080,300)	(6,536,096)	579,386
Employee LTIP rights	09 Feb 2022	1 Jul 2016	25,324	2,428	—	(27,752)	—
Employee LTIP rights	03 Oct 2022	1 Jul 2016	70,000	6,713	(19,179)	(57,534)	—
Employee LTIP rights	03 Oct 2022	1 Jul 2017	5,431,222	—	(829,577)		4,601,645
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	7,000,371	—	(555,973)	—	6,444,398
Employee LTIP rights	12 Nov 2024	1 Jul 2018	—	1,837,109	—	—	1,837,109
Employee LTIP rights	30 Jun 2024	1 Jul 2019	—	7,804,260	(451,085)	—	7,353,175
Employee STIP rights	13 Sep 2024	1 Jul 2018	—	3,311,771	—	(3,311,771)	—
Total			**22,264,516**	**13,580,557**	**(4,936,114)**	**(9,933,153)**	**20,975,806**

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 maintain the capital structure, the Group may issue new shares or other equity instruments.

On 27 September 2018, the Company executed a $10 million Equity Line of Credit (ELOC) facility with Long State Investment Limited (LSI). Under the terms of the facility, the Company may, at its discretion, issue shares to LSI at any time over 24 months from execution, up to a total of $10 million. The Company may draw down up to $250,000 in any period of 5 trading days.

Any shares issued to LSI will be priced at the lowest daily weighted average price (VWAP) of the Company shares traded on each of the 5-trading days which follow an advance notice by the Company. A commission of 5% will be payable by the Company at the time of issue.

LSI may receive up to five million unlisted options through four separate tranches, subject to ELOC utilisation. An initial tranche of 1.25 million options with an exercise price of 35 cents will be granted on activation of the ELOC. Further tranches of 1.25 million options, with an exercise price of 200% of the 20-day VWAP immediately preceding the date on which the Company is required to grant the options, will be granted when the aggregate advances first exceeds $2.5 million, $5 million, and $7.5 million. The options have an exercise period of five years from the date of issue.

To date, the Company has not utilised the ELOC facility and no options have been granted to LSI. The facility expires 27 September 2020.

21. RESERVES

	2020 $'000	2019 $'000
Share options reserve	**27,238**	**25,310**
Movements:		
Balance at start of year	25,310	23,464
Share based payment costs (a)	1,937	602
Options issued for financing	—	1,244
Transaction costs	(9)	—
Balance at end of year	**27,238**	**25,310**

(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

	2020 $'000	2019 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year (a)	(228,843)	(214,177)
Net profit/(loss) for the year	5,411	(14,526)
Balance at end of year	**(223,432)**	**(228,703)**

(a) 2020 restated for change in accounting policy. Refer to Statement of Changes in Equity and Note 1(aa).

23. EARNINGS/(LOSS) PER SHARE

		2020	2019
(a)	**Basic earnings/(loss) per share (cents)**	**0.75**	**(2.05)**
(b)	**Diluted earnings/(loss) per share (cents)**	**0.75**	**(2.05)**
(c)	**Profit/(loss) used in earnings/(loss) per share calculation**		
	Profit/(loss) attributed to ordinary equity holders ($'000)	**5,411**	**(14,526)**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic earnings/(loss) per share	**720,898,329**	**709,669,029**
	Adjustments for the calculation of diluted earnings per share:		
	Employee share rights	1,057,114	—
	Weighted average number of shares used as the denominator in calculating diluted earnings/(loss) per share	**721,955,443**	**709,669,029**

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. Additionally, in the prior year, any exercise of the options would be antidilutive as their exercise to ordinary shares would decrease the loss per share. In accordance with AASB 133, they are also excluded from the diluted loss per share calculation in 2019.

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.

24. SEGMENT REPORTING (CONTINUED)

(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.

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**

[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)

2019	Producing Assets 2019 $'000	Exploration Assets 2019 $'000	Unallocated Items 2019 $'000	Consolidation 2019 $'000
Revenue from contracts with customers				
Natural gas	49,658	—	—	49,658
Crude oil and condensate	9,700	—	—	9,700
Total revenue from contracts with customers	**59,358**	**—**	**—**	**59,358**
Cost of sales	(30,369)	—	—	(30,369)
Gross profit	**28,989**	**—**	**—**	**28,989**
Other income	19	—	6	25
Share based employee benefits	—	—	(602)	(602)
General and administrative expenses	—	—	(1,032)	(1,032)
Employee benefits and associated costs	—	—	(5,194)	(5,194)
EBITDAX	**29,008**	**—**	**(6,822)**	**22,186**
Depreciation and amortisation	(12,378)	—	(317)	(12,695)
Exploration expenditure	(14,803)	(999)	—	(15,802)
Interest revenue	103	1	256	360
Finance costs	(7,932)	(40)	(603)	(8,575)
Loss before income tax	**(6,002)**	**(1,038)**	**(7,486)**	**(14,526)**
Taxes	—	—	—	—
Loss for the year	**(6,002)**	**(1,038)**	**(7,486)**	**(14,526)**
Segment assets	**143,023**	**11,068**	**14,659**	**168,750**
Segment liabilities	**(158,285)**	**(2,991)**	**(13,091)**	**(174,367)**
Capital expenditure				
Property, plant and equipment	16,078	—	110	16,188
Intangibles	—	—	17	17
	16,078	**—**	**127**	**16,205**

	2020 $'000	2019 $'000
Revenue from external customers by geographical location of production:		
Australia	**65,046**	**59,358**
Non-current assets by geographical location:		
Australia	**124,500**	**139,164**

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.

	2020 $'000	**% of Sales Revenue**	2019 $'000	% of Sales Revenue
Largest customer	18,918	29%	22,706	38%
Second largest customer	12,712	20%	8,830	15%
Third largest customer	9,629	15%	7,154	12%
Fourth largest customer	8,504	13%	6,363	11%
Fifth largest customer	7,649	12%	5,695	10%

25. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2020 $'000	2019 $'000
Balance Sheet		
Current assets	21,983	16,128
Non-current assets	23,797	23,291
Total assets	45,780	39,419
Current liabilities	(21,749)	(28,344)
Non-current liabilities	(1,372)	(1,032)
Total liabilities	(23,121)	(29,376)
Net assets	**22,659**	**10,043**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	27,238	25,310
Accumulated losses	(202,355)	(213,043)
Total equity	**22,659**	**10,043**
Profit/(Loss) for the year	**10,829**	**(13,128)**
Total comprehensive profit/(loss)	**10,829**	**(13,128)**

(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 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 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:

			Equity Holding	
Name of Entity	Place of Incorporation	Class of Shares	2020 %	2019 %
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

	2020 $	2019 $
Short-term employee benefits	3,040,943	3,120,547
Post-employment benefits	166,369	179,537
Termination benefits	—	80,908
Long-term benefits	40,105	(81,319)
Share based payments	846,280	(21,388)
	4,093,697	**3,278,285**

Detailed remuneration disclosures are provided in the remuneration report on pages 30 to 43.

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

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

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'.

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 2020.

	2020 $'000	2019 $'000
Revenue from the sale of goods	26,505	18,046
Cost of sales	(11,389)	(14,437)
Gross profit	15,116	3,609
Other income	8,604	354
Share based employment benefits	(1,937)	(602)
General and administrative expenses	413	(300)
Depreciation and amortisation	(8,441)	(4,309)
Employee benefits and associated costs	(4,512)	(5,194)
Exploration expenditure	(5,234)	(15,482)
Finance costs	(4,367)	(5,252)
Impairment expense	(177)	—
Loss before income tax	(535)	(27,176)
Income tax credit	1,570	6,540
Profit/(Loss) for the year	1,035	(20,636)
Other comprehensive profit/(loss) for the year, net of tax	—	—
Total comprehensive profit/(loss) for the year	**1,035**	**(20,636)**
Accumulated losses at the beginning of the financial year	(214,888)	**(194,252)**
AASB 16 Lease accounting adjustments	(139)	—
Profit/(Loss) for the year	1,035	(20,636)
Accumulated losses at the end of the financial year	**(213,992)**	**(214,888)**

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.

	2020 $'000	2019 $'000
ASSETS		
Current assets		
Cash and cash equivalents	25,652	17,296
Trade and other receivables	3,941	3,398
Inventories	1,172	1,394
Total current assets	30,765	22,088
Non-current assets		
Property, plant and equipment	55,797	65,997
Right of use assets	833	—
Exploration assets	8,722	8,899
Intangible assets	286	73
Other financial assets	2,110	2,255
Deferred Tax Assets	5,456	5,636
Goodwill	3,906	3,906
Total non-current assets	77,110	86,766
Total assets	**107,875**	**108,854**
LIABILITIES		
Current liabilities		
Trade and other payables	13,800	13,699
Deferred revenue	1,983	1,983
Borrowings	3,846	6,675
Lease liabilities	562	—
Other financial liabilities	—	39
Provisions	4,062	4,380
Total current liabilities	24,253	26,776
Non-current liabilities		
Deferred revenue	18,537	15,119
Borrowings	35,389	39,224
Lease liabilities	431	—
Other financial liabilities	—	45
Provisions	18,243	19,491
Total non-current liabilities	72,600	73,879
Total liabilities	**96,853**	**100,655**
Net assets	**11,022**	**8,199**
EQUITY		
Contributed equity	197,776	197,776
Reserves	27,238	25,310
Accumulated losses	(213,992)	(214,887)
Total equity	**11,022**	**8,199**

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

	2020 $'000	2019 $'000
Profit/(loss) after income tax	**5,411**	**(14,526)**
Adjustments for:		
Depreciation and amortisation	16,257	12,695
Impairment expense	177	—
(Profit)/loss on disposal of assets	(51)	2
Profit on disposal of exploration permits	(8,393)	—
Share-based payments	1,937	602
Financing costs and interest (non-cash)	834	1,633
Changes in assets and liabilities relating to operating activities:		
Decrease / (increase) in trade and other receivables	2,290	(2,429)
Decrease in inventories	138	856
Decrease in trade and other payables	(481)	(829)
(Decrease)/increase in deferred revenue	(4,275)	1,349
Decrease in financial liabilities	—	(39)
Increase in provisions	1,883	3,151
Net cash inflow from operations	**15,727**	**2,465**

29. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

Non-cash interest relating to Other Financial Liabilities amounted to $56,000 (2019: $650,000). Additionally, non-cash revaluation credits amounted to $2,000 (2019 credit of $164,000). Refer Note 4(a).

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, an amount of $15,819,000 (2019: $Nil) was transferred to Deferred Revenue, reflecting the removal of the cash settlement option (Refer Note 18 for further details).

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

- Acquisition of right of use assets – Note 11(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

	2020 $'000	2019 $'000
Cash and cash equivalents	25,918	17,806
Borrowings and leases – repayable within one year	(7,572)	(10,957)
Borrowings and leases – repayable after one year	(64,427)	(70,773)
Net debt	**(46,081)**	**(63,924)**
Cash	25,918	17,806
Gross Debt – fixed interest rates	(1,226)	—
Gross debt – variable interest rates	(70,773)	(81,730)
Net debt	**(46,081)**	**(63,924)**

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 2018	**27,223**	**(78,327)**	**—**	**(51,104)**
Cash flows	(9,417)	(3,501)	—	(12,918)
Other non-cash movements	—	98	—	98
Net debt 30 June 2019	**17,806**	**(81,730)**	**—**	**(63,924)**
Recognised on adoption of AASB 16 (see Note 11)	—	—	(1,615)	(1,615)
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)**

30. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2020 in respect of certain joint arrangement payments. As partial consideration under the terms of the purchase agreement for EP105 and EP106, there is a requirement to pay the vendor the sum of $1,000,000 (2019: $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:

	2020 $'000	2019 $'000
The following amounts are due:		
Within one year	475	609
	475	**609**

(b) Exploration commitments

The Consolidated Entity has the following minimum exploration expenditure commitments:

	2020 $'000	2019 $'000
The following amounts are due:		
Within one year	10,578	12,175
Later than one year but not later than three years	55,087	46,105
Later than three years but not later than five years	8,100	4,450
Later than five years	—	6,000
	73,765	**68,730**

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. The leases have varying terms, escalation clauses and renewal rights. From 1 July 2019, the Group has applied AASB16 *Leases*, resulting in operating leases being recognised as right-of-use assets. The new policy is set out in Note 11(c) and the impact of the change of accounting policy can be found in Note 1(aa).

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:

	2020 $'000	2019 $'000
Within one year	10	658
Later than one year but not later than five years	—	1,059
Later than five years	—	181
	10	**1,898**

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 shown below (2019: nil).

Grant Date	Expiry Date	Balance at Start of Year	Granted During the Year	Exercise Price	Average Fair Value Per Option	Exercised During the Year	Cancelled or Expired During the Year	Balance at End of Year	Vested and Exercisable
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 fair value of options granted during the year was $0.111 (2019: none granted) and the weighted average remaining contractual life at 30 June 2020 was 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 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
2020							
09 Aug 2019	30 Jun 2019	—	3,311,771	$0.155	(3,311,771)	—	—
2019							
22 Mar 2019	30 Jun 2018	—	1,634,631	$0.130	(1,634,631)	—	—

The weighted average fair value of share rights issued under the Short Term Incentive Plan during the year was $0.142 (2019: $0.13).

(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.

32. SHARE BASED PAYMENTS (CONTINUED)

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

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
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	$0.190	—	(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 weighted average fair value of share rights granted under the Long Term Incentive Plan during the year was $0.150 (2019: $0.088).

The weighted average remaining contractual life of outstanding share rights at the end of the year was 3.6 years (2019: 3.9 years).

The fair values of deferred share rights granted are valued using methodology that takes into account market and peer performance hurdles. The values 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 following factors and assumptions were used in determining the fair value of rights 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
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)

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

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
2019							
09 May 2019	30 June 2019	—	791,808	$0.101	—	—	791,808
17 Apr 2019	30 June 2019	—	49,321	$0.111	—	—	49,321
17 Apr 2019	30 June 2019	—	7,816	$0.150	—	—	7,816
24 Sep 2019	30 June 2019	—	5,784,715	$0.087	—	—	5,784,715
24 Sep 2019	30 June 2019	—	366,711	$0.120	—	—	366,711
02 Oct 2018	30 June 2016	—	781,438	$0.067	(395,964)	(384,835)	639
27 Jun 2018	30 June 2018	135,920	—	$0.102	—	—	135,920
16 May 2018	30 June 2018	6,562	—	$0.126	—	—	6,562
16 May 2018	30 June 2018	10,306	—	$0.175	—	—	10,306
29 Nov 2017	30 June 2018	1,835,910	—	$0.055	—	(1,835,910)	—
29 Sep 2017	30 June 2015	7,041	—	$0.097	(7,041)	—	—
01 Sep 2017	30 June 2018	6,124,904	—	$0.081	—	(926,672)	5,198,232
01 Sep 2017	30 June 2018	262,500	—	$0.115	—	(29,510)	232,990
01 Sep 2017	30 June 2017	70,000	—	$0.082	—	—	70,000
01 Sep 2017	30 June 2016	327,000	—	$0.056	(161,865)	(165,135)	—
24 Jan 2017	30 June 2017	25,324	—	$0.190	—	—	25,324
16 Nov 2016	30 June 2017	6,050,315	—	$0.151	—	(3,419,207)	2,631,108
20 Oct 2016	30 June 2017	7,053,384	—	$0.106	—	(445,428)	6,607,956
20 Oct 2016	30 June 2017	372,385	—	$0.135	—	(33,943)	338,442
20 Oct 2016	30 June 2016	18,517	—	$0.135	(18,517)	—	—
20 Oct 2016	30 June 2016	106,666	—	$0.087	(52,800)	(53,866)	—
22 Dec 2015	30 June 2016	1,913,873	—	$0.123	(1,038,000)	(875,873)	—
03 Dec 2015	30 June 2016	6,063	—	$0.165	(6,063)	—	—
09 Nov 2015	30 June 2016	515,083	—	$0.184	(285,881)	(222,536)	6,666
14 Oct 2015	30 June 2016	5,261,487	—	$0.147	(2,565,732)	(2,695,755)	—
17 Jun 2015	30 June 2015	73,429	—	$0.074	(73,429)	—	—
Totals		**30,176,669**	**7,781,809**		**(4,605,292)**	**(11,088,670)**	**22,264,516**

The following factors and assumptions were used in determining the fair value of share rights granted during FY2019:

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 Sep 2018	22 May 2024	$0.087	Nil	$0.120	86%	2.33%	—
02 Oct 2018[1]	Various	$0.067	Nil	$0.135	N/A	N/A	—
22 Mar 2019[2]	10 Apr 2024	$0.130	Nil	$0.130	N/A	N/A	—

1 *Adjustment to number of LTIP Rights for plan year commencing 1 July 2015 – valued at the market price of the known vesting %.*
2 *STIP Rights fully vested on issue – valued at market price on issue.*

(d) Expenses arising from share-based payment transactions

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

	2020 $	2019 $
Share Rights issued to employees	**1,937,011**	**601,897**

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 2020 is nil (2019: nil), no loss allowance provision has been recorded at 30 June 2020 (2019: 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	**2020 $'000**	2019 $'000	**2020 $'000**	2019 $'000
Current: 0-30 days	5,453	7,830	—	—
	5,453	**7,830**	**—**	**—**

The receivables at 30 June 2020 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 Risk Committees. The primary function of these Committees 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:

2020 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	25,918	—	—	—	25,918	25,918
Trade and other receivables	5,453	—	—	—	5,453	5,453
Other financial assets	—	—	2,656	—	2,656	2,656
	31,371	**—**	**2,656**	**—**	**34,027**	**34,027**
Financial Liabilities						
Trade and other payables	(5,073)	(214)	—	—	(5,287)	(5,287)
Interest bearing liabilities	(5,355)	(6,227)	(64,837)	(143)	(76,562)	(71,999)
Other financial liabilities	—	—	—	—	—	—
	(10,428)	**(6,441)**	**(64,837)**	**(143)**	**(81,849)**	**(77,286)**
2019 ($'000)						
Financial Assets						
Cash and cash equivalents	17,806	—	—	—	17,806	17,806
Trade and other receivables	7,830	—	—	—	7,830	7,830
Other financial assets	—	—	2,771	—	2,771	2,771
	25,636	**—**	**2,771**	**—**	**28,407**	**28,407**
Financial Liabilities						
Trade and other payables	(6,006)	—	—	—	(6,006)	(6,006)
Interest bearing liabilities	(12,233)	(4,463)	(72,039)	—	(88,735)	(81,730)
Other financial liabilities	—	(2,057)	(14,879)	—	(16,936)	(15,849)
	(18,239)	**(6,520)**	**(86,918)**	**—**	**(111,677)**	**(103,585)**

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	
	2020 %	2019 %	**2020 $'000**	2019 $'000	**2020 $'000**	2019 $'000	**2020 $'000**	2019 $'000	**2020 $'000**	2019 $'000
Financial Assets:										
Cash and cash equivalents	0.3	1.3	25,918	17,806	—	—	—	—	25,918	17,806
Trade and other receivables	—	—	—	—	—	—	5,453	7,830	5,453	7,830
Other financial assets	0.2	0.9	—	—	1,083	1,163	1,573	1,608	2,656	2,771
Total Financial Assets			**25,918**	**17,806**	**1,083**	**1,163**	**7,026**	**9,438**	**34,027**	**28,407**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(5,287)	(6,006)	(5,287)	(6,006)
Interest bearing liabilities	5.6	6.8	(70,773)	(81,730)	(1,226)	—	—	—	(71,999)	(81,730)
Other financial liabilities	—	—	—	—	—	—	—	(15,849)	—	(15,849)
Total Financial Liabilities			**(70,773)**	**(81,730)**	**(1,226)**	**—**	**(5,287)**	**(21,855)**	**(77,286)**	**(103,585)**
Net Financial Assets / (Liabilities)			**(44,855)**	**(63,924)**	**(143)**	**1,163**	**1,739**	**(12,417)**	**(43,259)**	**(75,178)**

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 2019.

	Profit or Loss		Equity	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2020 ($'000)				
Cash and cash equivalents	7	(7)	—	—
Interest bearing liabilities	(397)	397	—	—
2019 ($'000)				
Cash and cash equivalents	23	(23)	—	—
Interest bearing liabilities	(558)	558	—	—

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)

(d) Commodity Risk (continued)

In 2019 other financial liabilities included amounts recognised under a Gas Sale & Prepayment Agreement entered into in 2016 whereby the customer could elect for a financial settlement in lieu of taking physical delivery of gas. In July 2019 the customer novated its rights and obligations under the contract to a third party and a financial settlement option no longer exists. The balance of the financial liability at the time of novation was transferred to deferred revenue (see Note 18 and Note 2(b)). Prior to the novation, the financial settlement amount was either a base price per the agreement, or the weighted average price of gas delivered under any new Gas Sales Agreements (GSA) entered into by the Consolidated Entity and supplied from the production area, or a combination of both. The first new GSA commenced June 2017.

Volume Sensitivity

The financial liability is valued based on achieving take or pay volumes under new GSA's in existence. A sensitivity of 10% has been selected on the deliverable volumes under the new GSA's to show the impact on the carrying value:

	Profit or Loss		Equity	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2020 ($'000)				
Other financial liabilities	—	—	—	—
2019 ($'000)				
Other financial liabilities	—	919	—	—

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

Price Sensitivity

A sensitivity of 1% of the weighted average gas price under new GSA's has been selected to show the impact on the carrying value of the financial liability:

	Profit or Loss		Equity	
	1% Increase	1% Decrease	1% Increase	1% Decrease
2020 ($'000)				
Other financial liabilities	—	—	—	—
2019 ($'000)				
Other financial liabilities	(158)	158	—	—

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

(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 2021 (2019: 30 September 2020). Repayments comprise fixed quarterly principal repayments of $1,000,000 along with accrued interest to September 2020 and $2,000,000 per quarter thereafter. 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.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(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 US dollars from its continuing operations, which are disclosed in Australian dollars:

	2020 $'000	2019 $'000
Trade and other receivables	677	1,923
Trade and other payables	(153)	(138)

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

	2020 $'000	2019 $'000
Australian dollar/ US dollar +10%	(62)	(162)
Australian dollar/ US dollar -10%	75	198

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	**2020 %**	2019 %
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 106 (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	60.00
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) under the following classifications:

	2020 $'000	2019 $'000
Current assets		
Cash and cash equivalents	666	510
Trade and other receivables	4,243	6,224
Inventory	1,409	1,325
Other financial assets	—	—
Total current assets	6,318	8,059
Non-current assets		
Property, plant and equipment	52,074	57,519
Right of use assets	225	—
Other financial assets	301	301
Total non-current assets	52,600	57,820
Current liabilities		
Trade and other payables	1,963	541
Accruals	1,531	1,275
Lease liabilities	46	—
Deferred revenue	731	731
Provision for production over-lift	712	—
Restoration provision	119	—
Total current liabilities	5,102	2,547
Non-current liabilities		
Deferred revenue	439	439
Lease liabilities	187	—
Provision for production over-lift	3,461	4,008
Restoration provision	21,433	19,595
Total non-current liabilities	25,520	24,042
Net assets	**28,296**	**39,290**
Joint arrangement contribution to loss before tax		
Revenue	38,541	42,992
Other income	10	22
Expenses	(26,849)	(25,909)
Profit before income tax	**11,702**	**17,105**

35. EVENTS OCCURRING AFTER THE REPORTING PERIOD

Amadeus to Moomba Gas Pipeline

In August, Central announced an agreement to work with Australian Gas Infrastructure Group and Macquarie Mereenie Pty Ltd towards a FID on a proposed new pipeline to enable Central's gas to be transported direct to the Moomba gas supply hub and the larger south-eastern Australian gas markets at a lower cost than existing routes.

Issue of shares

On 18 September 2020, the Company issued 146,215 shares to employee participants in the $1,000.00 Exempt Plan.

Issue and cancellation of share rights

On 18 September 2020, the Company issued 10,179,464 Share Rights pursuant to the Employee Rights Plan. The Company also cancelled 717,033 Share Rights on the same date and a further 211,528 on 23 September 2020.

No other matter or circumstance has arisen between 30 June 2020 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 45 to 94 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 2020 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 2020.

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:

Wrixon Gasteen
Director
Brisbane

24 September 2020

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 2020 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 2020
- 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 profit or loss and other 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 $1.6 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 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 matters to the Audit and Risk Committee: – Basis of preparation of the financial report – Recoverability of producing assets (including goodwill) and exploration assets • These are further described in the *Key audit matters* section of our report.

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***
Basis of preparation of the financial report *(Refer to note 1(a)(i) of the financial report)* As described in Note 1 to the financial report, the financial statements have been prepared by the Group on a going concern basis, which contemplates that the Group will continue to meet its commitments, realise its assets and settle its liabilities in the normal course of business. Assessing the appropriateness of the Group's basis of preparation for the financial report was a key audit matter due to its importance to the financial report and the level of judgement involved in assessing future funding and operational status, in particular with respect to the Group forecasting future cash flows for a period of at least 12 months from the date of the financial report (cash flow forecasts).	In assessing the appropriateness of the Group's going concern basis of preparation of the financial report, we performed the following procedures, amongst others: • Evaluated the appropriateness of the Group's assessment as to their ability to continue as a going concern, including whether the level of analysis is appropriate given the nature of the Group; checking that the period covered is at least 12 months from the date of the auditor's report; and that relevant information of which the auditor is aware as a result of the audit has been considered; • Enquired of management and the board of directors as to its knowledge of events or conditions that may cast doubt on the Group's ability to continue as a going concern; • Assessed the cash flow forecast by evaluating the reliability of selected underlying data and considered evidence around key assumptions in the Group's cash flow forecasts; • Performed a sensitivity analysis by varying key assumptions, including the timing and amount of expenditure, in the cash flow forecasts, to assess the impact on financing facilities utilised in the event that actual performance varies from that assumed in the Group's forecasts; • Obtained an understanding and requested representations from management and the Board of Directors regarding their plans for future action and the feasibility of these plans, including the availability of alternative sources of funds, if required; • We evaluated whether, in view of the requirements of Australian Accounting Standards, the financial report provides adequate disclosure on the Group's going concern assessment.

Key audit matter	*How our audit addressed the key audit matter*
Recovery of producing assets (including goodwill) and exploration assets *(Refer to notes 10, 12 & 15)* At 30 June, the Group recognised $3.91 million of goodwill, $107.85 million of property, plant and equipment, and $8.72 million of exploration assets on the consolidated balance sheet. *Producing assets* Goodwill is monitored by management at the level of the operating segment and has been allocated to the producing assets cash generating unit (the producing assets CGU). In line with Australian Accounting Standards, which require companies to test goodwill for impairment annually, the Group have performed impairment tests for the producing assets CGU as at 30 June 2020, and determined the recoverable amount by using the fair value less cost of disposal (FVLCD) methodology utilising a discounted cashflow model (the impairment model). The Group concluded that there was no impairment of the producing assets cash generating unit (the CGU assets). *Exploration assets* Each area of interest is 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 in line with the requirements of AASB 6 *Exploration for and Evaluation of Mineral Resources*. The Group concluded that there was impairment for two areas of interest , totalling $0.17 million. We considered managements assessments into the recovery of producing assets (including goodwill) and exploration assets to be a key audit matter given the significance of the assets to the consolidated balance sheet, the early stages in the development lifecycle of these assets, and the significant judgement involved in determining the cash flow forecasts in the impairment model.	To evaluate the Group's assessment of the recoverable amount of the producing assets CGU, we performed a number of procedures including the following: • 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, liabilities and cash flows, • Considered whether the discounted cash flow model used to estimate the recoverable amount of the CGU on a 'fair value less cost of disposal' basis (the impairment model) was consistent with Australian Accounting Standards, • Compared the forecast cash flows used in the impairment model to the most recent budgets and business plans approved by the board, • Considered whether the forecast cash flows in the impairment model were reasonable and based upon supportable assumptions, by comparing: ○ oil and gas price data used in the impairment model to industry forecasts, and ○ forecast oil and gas production over the life of fields to the Group's most recent reserves and resources statement • Assessed, with assistance from PwC valuation experts that the post-tax nominal discount rate applied in the model reflects the risks of the CGU • evaluated the Group's historical ability to forecast future cash flows by comparing budgets with the reported actual results for the past three years,

Key audit matter	*How our audit addressed the key audit matter*
	• performed tests, on a sample basis of the mathematical accuracy of the impairment model calculations, • evaluated the adequacy of disclosures made in note 15 of the financial statements, including those regarding key assumptions used in the impairment assessment in light of the requirements of the Australian Accounting Standards. To evaluate the Group's assessment of the recoverable amount of exploration assets, we performed a number of procedures including the following: • met with key operational and finance staff to develop an understanding of the current status and future intention for each area of interest, • obtained and read relevant support including internal and external documents for current and future intentions for each area of interest, • considered that areas of interest that remain capitalised are included in future budgets and operational plans of the Group, • ascertained licence expiry dates of the areas of interest to assess whether there were any areas where the Group's right to explore is either at, or close to, expiry. • evaluated the adequacy of the impairment charge, 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 2020, 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 30 to 43 of the directors' report for the year ended 30 June 2020.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2020 complies with section 300A of the *Corporations Act 2001*.

pwc

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

Tim Allman
Partner

Brisbane
24 September 2020

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 21 SEPTEMBER 2020

Top holders

The 20 largest registered holders of the quoted securities as at 21 September 2020 were:

	Name	No. of Shares	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	35,791,682	4.95
2	UBS Nominees Pty Ltd	29,906,170	4.13
3	Fanchel Pty Ltd	19,000,000	2.63
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	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.96
6	Citicorp Nominees Pty Limited	13,961,704	1.93
7	Brazil Farming Pty Ltd	13,500,000	1.87
8	Mr Raymond Driscoll + Mrs Karyn Driscoll + Mr Jarrod Driscoll <The Edwin Holdings S/F A/c>	8,936,608	1.24
9	Kensington Capital Partners Pty Ltd	7,923,341	1.10
10	Chembank Pty Limited <Philandron A/C>	7,000,000	0.97
11	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	6,700,000	0.93
12	Mr Philip Gasteen <Thrushton Investment A/C>	6,501,255	0.90
13	Mr William Bambling + Mrs Joyce Bambling	6,300,000	0.87
14	Mr Donald Leonard Cottee	5,581,344	0.77
15	Mr Stuart Francis Howes	5,501,001	0.76
16	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/C>	5,000,001	0.69
17-19	Chembank Pty Limited <R T Unit A/C>	5,000,000	0.69
17-19	Dynasty Peak Pty Ltd <The Avoca Super Fund A/C>	5,000,000	0.69
17-19	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	5,000,000	0.69
20	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	4,000,000	0.55
	Total	**222,341,421**	**30.73**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 21 September 2020 was:

	Number of Holders		
Size of Holding	Listed Fully Paid Shares	Unlisted Share Rights	Unlisted Options
1 - 1,000	758	3	—
1,001 -5,000	1,889	8	—
5,001 - 10,000	1,083	11	—
10,001 - 100,000	2,760	45	—
100,001 - Over	1,007	30	5
Total	**7,497**	**97**	**5**

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 21 September 2020 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

Holder	Units
Troy Harry	46,683,341

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 3,847 shares as at 21 September 2020):

Holders	Units
2,150	3,340,858

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 (3rd edition) published by the ASX Corporate Governance Council.

The 2020 Corporate Governance Statement is dated as at 30 June 2020 and reflects the corporate governance practices in place throughout the 2020 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) [1]	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	30	Santos	70
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)	Amadeus Basin NT	Central	100	100		
OL4 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie Pty Ltd (Macquarie Mereenie)	50
OL5 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
L6 (Surprise)	Amadeus Basin NT	Central	100	100		
L7 (Dingo)	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 [3]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA129	Wiso Basin NT	Central	100	100		
EPA130	Pedirka Basin NT	Central	100	100		
EPA131 [4]	Pedirka Basin NT	Central	100	0		
EPA132	Georgina Basin NT	Central	100	100		
EPA133 [5]	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 [3]	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	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
PL30	Amadeus Basin NT	Central	100	100		

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES AT THE DATE OF THIS REPORT

Notes:

1 *As announced on 16 July 2020, prior to 31 July 2021 Santos can elect that Central be carried for the first $3 million of Dukas-1 well costs. In return for a carry by Santos and if Santos so elects, Central will transfer 30% equity in EP82 (excluding the Orange prospect) to Santos. Should Santos not carry Central in exchange for the option to have 30% equity in EP82, its interest in EP112 (including Dukas-1 well) 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 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.*

4 *The exploration permit application has been disposed. Transfer of the registered interest is awaiting the grant of an exploration permit.*

5 *This exploration permit application was placed into moratorium on 22 October 2015 for a five (5) year period ending on 22 October 2020.*

CORPORATE DIRECTORY

CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

DIRECTORS

Mr Stuart Baker BE(Elec), MBA, AICD, Non-Executive Director
Mr Leon Devaney BSc MBA, Managing Director and Chief Executive Officer
Dr Julian Fowles PhD, BSc (Hons), GDipAFI, GAICD, Non-Executive Director
Mr Wrixon F Gasteen BE(Mining) (Hons), MBA (Distinction), Non-Executive Director and Chairman
Ms Katherine Hirschfeld AM, BE(Chem), HonFIEAust, FTSE, FIChemE, CEng, FAICD, Non-Executive Director
Dr Agu Kantsler BSc (Hons), PhD, GAICD, FTSE, Non-Executive Director
Mr Michael (Mick) McCormack BSurv, GradDipEng, MBA, FAICD, Non-Executive Director

GROUP GENERAL COUNSEL AND COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

REGISTERED OFFICE

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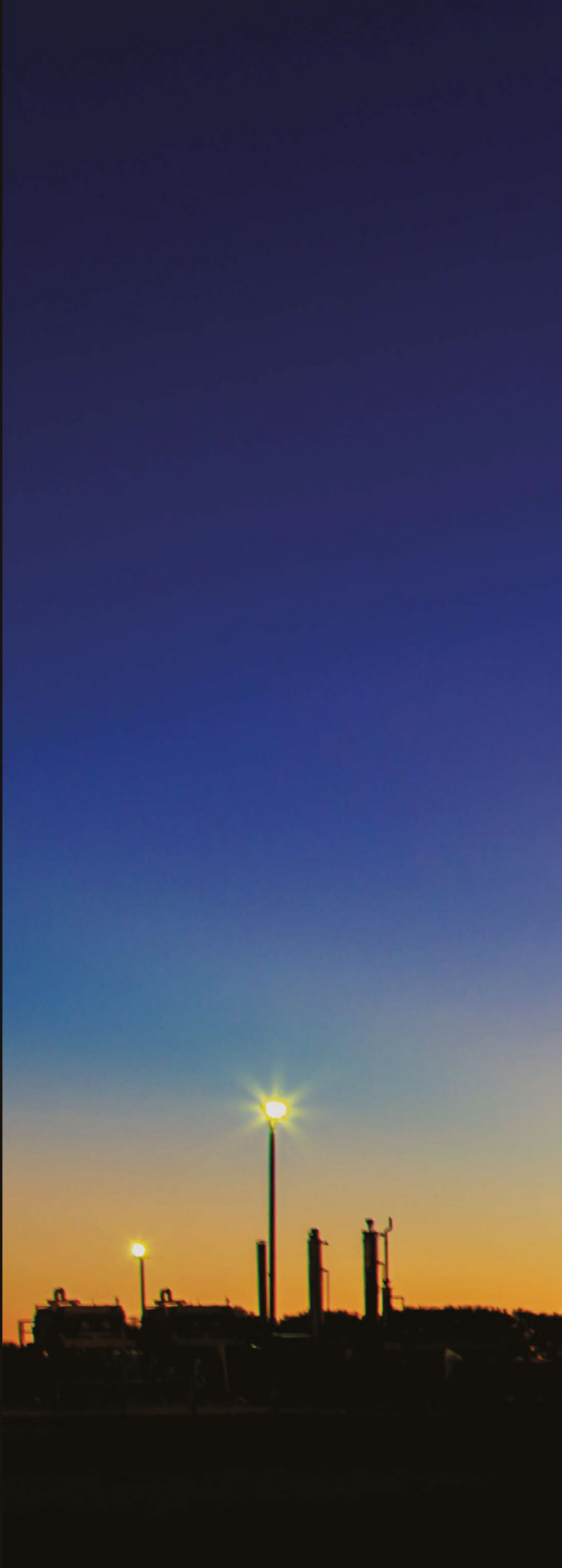
STOCK EXCHANGE LISTING

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



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