Q2 FY19

Quarterly Report for 3 months to 31 December 2018

23 January 2019

Key features:

- **Quarterly production:** 0.29 million boe down from previous quarter's 0.37 million boe due to scheduled maintenance
- **Quarterly revenue:** $14.4 million down from $21.8 million in prior quarter due to lower gas and oil volumes
- **Half-year sales revenue:** up 16% to $36.2 million from $31.2 million
- **Sole Gas Project:** 86% complete at 31 December, within budget
- **Prospective Resources announcement:** assessment of Prospective Resource for offshore Otway Basin prospects
- **Finance facility:** available funds increased and funds released, following review of Sole Gas Project cost and time to complete
- **Exploration activity:** drill rig contracted for offshore Otway drilling in June quarter 2019

Managing Director's comments

"The Sole Gas Project has progressed to be 86% complete at end December and we have committed to an offshore exploration program that can generate the next wave of growth.

"The increased funds available and released from our finance facility recognises the cost performance and outlook for the Sole Gas Project. We have flexibility to pursue the growth opportunities in our portfolio and have acted quickly, securing a rig and committing to drill two attractive gas prospects in our offshore Otway acreage.

"We expect the coming six months to be as momentous as any in the company's history as Sole is completed; we drill the Annie and Elanora prospects in the offshore Otway Basin; conclude gas contracts and, prepare to acquire the Minerva Gas Plant with the upside it offers for our operating margin, cash generation and production."

Key measures

$ million unless indicated	3 months to 31 Dec 18	Prior Qtr Sept 18	Qtr on Qtr change %	FY19 YTD	FY18 PCP	YTD change %
Production MMboe	0.29	0.37	*- 22%*	0.66	0.81	*- 19%*
Sales revenue	14.4	21.8	*-34%*	36.2	31.2	*16%*
Capital expenditure (cash)	44.0	76.2	*-42%*	120.2	80.8	*49%*
Cash	193.9	203.8	*-5%*	193.9	283.3	*-32%*
Net cash/(debt)	7.5	50.6	*-85%*	7.5	193.7	*- 96%*

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Managing Director	Investor Relations

Financial

Sales

Sales revenue for the 3 months to 31 December 2018 (the December quarter) was $14.4 million, lower than the prior quarter's $21.8 million due to lower gas production and sales volume of crude oil.

Half year sales revenue of $36.2 million was 16% higher than the FY18 first half sales of $31.2 million due to higher prices for gas and oil.

Cash and borrowings

Cash at 31 December 2018 was $193.9 million, compared with $203.8 million at the beginning of the quarter.

Borrowings increased from $153.2 million to $186.4 million as debt was drawn to fund capital expenditure on the Sole Gas Project.

During the period the company's financiers agreed to a redetermination of the borrowing base and associated mandatory equity requirements for the project-based finance facility after consideration of the Sole Gas Project forecast cost to complete. The redetermination has secured an increase in available debt within the facility of approximately $18 million and the release of approximately $23 million of equity funds for general corporate purposes.

Hedging

Cooper Energy uses hedging to protect against downside oil price scenarios and retain partial exposure to higher oil prices. Hedging in place as at 31 December 2018 is as follows:

(bbl remaining as at 31 December 2018):	FY19 Q3	FY 19 Q4	Total
US$55.00 – U$79.50: zero cost collar options	8,180	1,632	9,812

Capital expenditure

Cash payments for capital expenditure during the quarter totaled $44.0 million, compared with $76.2 million in the September quarter. Incurred capital expenditure during the quarter was $41.0 million.

Incurred capital expenditure by region is as follows.

Capital expenditure (incurred)

	December quarter FY19			Year to date FY19		
$ million	Exploration	Development	Total	Exploration	Development	Total
Otway Basin	0.9	2.5	3.4	1.1	3.4	4.5
Gippsland Basin	1.0	35.8	36.8	1.6	100.9	102.5
Cooper Basin	0.1	0.3	0.4	-	0.3	0.3
Other	-	0.4	0.4	-	0.6	0.6
Total	2.0	39.0	41.0	2.7	105.2	107.9

Revised incurred capital expenditure guidance

Incurred capital expenditure guidance for FY19 has been updated to reflect first half performance and revised exploration and development plans for the FY19 second half. The commitment to an offshore drilling program, outlined in the Operations Review commencing on page 6 is the principal variation to previous guidance.

Expenditure guidance by activity and area of operation for the six months to June 2019 and expected full year total is outlined in the following table. This updated guidance, which totals $244.8 million, supersedes guidance issued in August totaling $183.0 million. The updated guidance includes expenditure attributable to the Annie and Elanora exploration wells in the Otway Basin and expenditure on the Sole Gas Project previously expected to fall outside FY19. The previous guidance did not include capitalised financing costs and interest, which has been recognised in the FY19 first half incurred capital expenditure.

Gippsland capital expenditure figures include the Sole project and capitalised interest incurred in the year to date as well as expenditure on Manta front end engineering.

$ million incurred	FY19 H1 Actual			FY19 H2 Guidance			FY19 Guidance		
	Exploration	Development	Total	Exploration	Development	Total	Exploration	Development	Total
Otway	1.1	3.4	4.5	40.5	17.8	58.3	41.6	21.2	62.8
Gippsland	1.6	100.9	102.5	2.2	70.0	72.2	3.8	170.9	174.7
Cooper	-	0.3	0.3	3.3	1.9	5.2	3.3	2.2	5.5
Other non-classified	-	0.6	0.6	-	1.5	1.5	-	2.1	2.1
Total	2.7	105.2	107.9	46.0	91.2	137.2	48.7	196.4	244.8

Gas marketing

During the quarter the company completed contracting of Casino Henry gas production for the 2019 calendar year. Cooper Energy's gas portfolio includes supply contracts with AGL Energy, Alinta Energy, EnergyAustralia, O-I Australia, Santos and Origin Energy.

The company holds approximately 119 PJ of uncontracted proved and probable reserves. Discussions with industrial and utility customers are underway for uncontracted volumes with a view to securing further contracts prior to the conclusion of the current financial year.

Key quarterly financial statistics

Refer notes below for information on calculation		Dec qtr 18	Prior qtr Sept 18	PCP qtr Dec 17	Change on prior qtr %	Change on PCP %	FY19 YTD	FY18 YTD	YTD change %
Sales									
Sales revenue	$ million	14.4	21.8	16.8	-34%	-14%	36.2	31.2	16%
Average realised oil price	AUD/bbl	114.78	113.65	80.84	1%	42%	114.21	72.17	58%
Oil direct operating cost	AUD/bbl	35.52	37.01	33.05	-4%	7%	36.29	32.49	12%
Sales volume	Gas PJ	1.4	1.9	1.8	-26%	-22%	3.3	3.9	-15%
	Oil kbbl	55.7	59.8	73.6	-7%	-24%	115.5	134.3	-14%
	Condensate kboe	1.2	1.3	1.6	- 8%	- 25%	2.4	3.6	- 33%
Capital Expenditure (incurred)									
Exploration & appraisal	$ million	2.0	0.7	1.6	186%	25%	2.7	24.9	-89%
Development & fixed assets	$ million	39.0	66.2	18.3	-41%	113%	105.2	52.2	102%
Total incurred capital expenditure		41.0	66.9	19.9	-39%	106%	107.9	77.1	40%
Capital Expenditure (cash)	$ million	44.0	76.2	47.8	-42%	-8%	120.2	80.8	49%
Cash									
Cash and term deposits	$ million	193.9	203.8	283.3	-5%	-32%	193.9	283.3	-32%
Cash held in escrow	$ million	1.7	5.8	-	-71%	100%	1.7	-	100%
Investments	$ million	1.6	1.9	1.8	-16%	-11%	1.6	1.8	- 11%
Total financial assets		197.2	211.5	285.1	-7%	-31%	197.2	285.1	-31%
Total debt	$ million	186.4	153.2	89.6	22%	108%	186.4	89.6	108%
Net cash/(debt)	$ million	7.5	50.6	193.7	-85%	-96%	7.5	193.7	-96%
Issued Capital									
Issued shares	million	1,621.6	1,601.1	1,601.1	1%	1%	1,621.6	1,601.1	1%
Performance Rights	million	16.0	17.8	17.8	-10%	-10%	16.0	17.8	-10%
Share Appreciation Rights	million	39.8	46.0	46.0	-13%	-13%	39.8	46.0	-13%

Notes:

- Sales figures for most recent quarter are preliminary
- Sales revenue includes impacts from provisional pricing. Under the new accounting standard AASB 15 *Revenue from Contracts with Customers* which was adopted by the Company on 1 July 2018, movements in provisional pricing will be disclosed separately in the financial report
- Prior periods have been updated for final reconciled figures
- Direct operating costs include production, transport and royalties
- Investments shown at fair value at the reporting date shown
- n/m = not meaningful

Production

Gas production of 1.40 PJ for the December quarter was 25% lower than the previous quarter due to lower production from the Casino Henry gas field with scheduled maintenance at the Iona gas plant and the temporary shut-in of the Netherby-1 well, both as advised in the previous quarterly report. Improved performance at the Minerva field partially offset this reduction.

Crude oil and condensate production of 59.99 kbbl was 4% lower than the previous quarter.

Quarterly production by project is discussed under 'Operations review', commencing on the following page.

Full year production guidance of 1.4 MMboe is unchanged.

Cooper Energy share of production for 3 months to 31 December 2018 and year to date

By product	Dec qtr 18	Prior qtr Sept 18	PCP qtr Dec 17	Change on prior qtr %	Change on PCP %	FY19 YTD	FY18 PCP	YTD change %
Sales gas PJ	1.40	1.88	1.76	*-25%*	*-20%*	3.28	3.87	*-15%*
Crude oil & condensate kbbl	59.99	62.49	76.74	*-4%*	*-22%*	122.47	140.82	*-13%*
Total MMboe	0.29	0.37	0.38	*-22%*	*-24%*	0.66	0.81	*-19%*

By project	Dec qtr 18	Prior qtr Sept 18	PCP qtr Dec 17	Change on prior qtr %	Change on PCP %	FY19 YTD	FY18 PCP	YTD change %
Casino Henry								
- gas PJ	1.11	1.63	1.41	*-32%*	*-21%*	2.74	3.13	*-12%*
- condensate kbbl	0.34	0.52	0.76	*-35%*	*-55%*	0.86	1.88	*-54%*
Minerva								
- gas PJ	0.29	0.25	0.34	*16%*	*-15%*	0.55	0.73	*-25%*
- condensate kbbl	0.87	0.74	0.87	*18%*	-	1.61	1.77	*-9%*
Cooper Basin								
- oil kbbl	58.78	61.23	75.12	*-4%*	*-22%*	120.01	137.18	*-13%*
Total (MMboe)	0.29	0.37	0.38	*-22%*	*-24%*	0.66	0.81	*-19%*

Note: figures rounded. As a result, some totals and percentage changes displayed may not equate with calculation from figures displayed.

Operations review

Otway Basin

Offshore

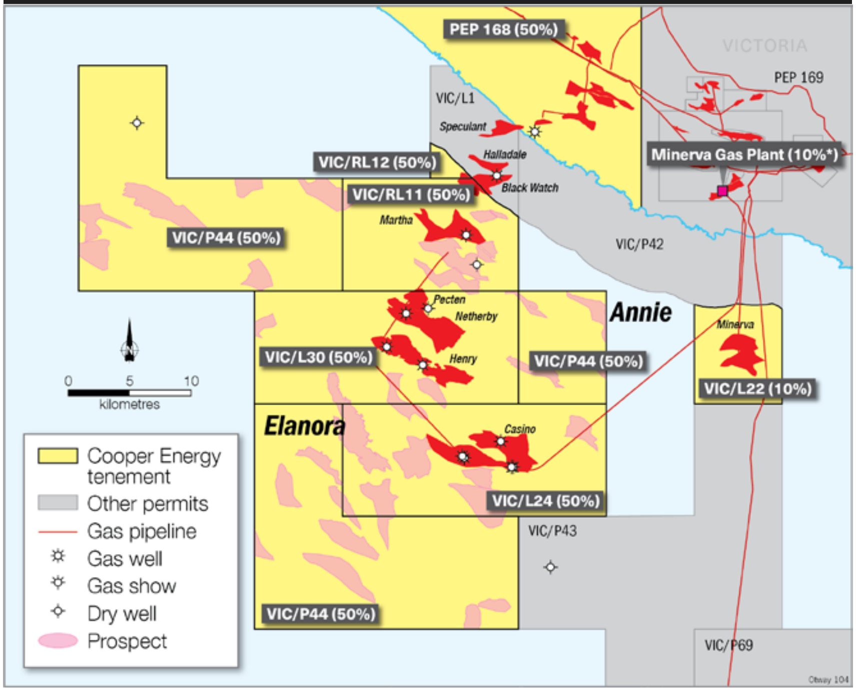
The company's interests in the Otway Basin offshore Victoria include:

a) a 50% interest in, and Operatorship of, the producing Casino Henry Netherby ("Casino Henry") Joint Venture (VIC/L24 and VIC/L30);

b) a 50% interest in, and Operatorship of, Retention Leases VIC/RL11 and VIC/RL12 which contain part of the undeveloped Black Watch gas field. An application to convert these retention leases to a production licence has been submitted;

c) a 50% interest in, and Operatorship of, the VIC/P44 exploration permit; and

Otway Basin, offshore



d) a 10% interest in the Minerva gas project comprising the offshore licence VIC/L22 and the Minerva Gas Plant, onshore Victoria. The Casino Henry Joint Venture has contracted to acquire the Minerva Gas Plant on cessation of the plant processing gas from the Minerva field.

As reported in the previous quarterly report the company announced the signing of a contract with O-I Australia for the supply of gas from Casino Henry in 2019 on 10 October. Casino Henry gas production for 2019 is now fully contracted.

Production

Cooper Energy's share of production from the offshore Otway Basin during the December quarter comprised 1.40 PJ of gas and 1.21 kbbl of condensate.

Casino Henry contributed gas production of 1.11 PJ, lower than the previous quarter's 1.63 PJ following the scheduled maintenance shutdown of the Iona Gas Plant in October and the ongoing shut-in of Netherby-1 advised in the previous quarterly report. Processing at the Iona Gas Plant resumed in early November after a 21-day interruption. Daily production rates benefited from optimisation work conducted in collaboration with Lochard Energy in December to lower inlet pressure at the Iona Gas Plant.

The subsea control system issue which necessitated the suspension of production from Netherby-1 in August is to be remedied by the full control system repair and upgrade campaign scheduled for April 2019. This work will include restoration of full control system functionality and operational redundancy with upgrades to enable connection of additional wells in the event of exploration success at the Annie and Elanora prospects. The interim reconfiguration attempted in October was unsuccessful.

Casino Henry also contributed 0.34 kbbl of condensate to December quarter production compared with 0.52 kbbl in the previous quarter.

Production from the Minerva gas field increased as a result of the switch to the Minerva-4 well in November. Minerva contributed 0.29 PJ of gas for the quarter compared to 0.25 PJ in the September quarter. The field is approaching end of life and the shut-in of Minerva-3 and switch to Minerva-4 resulted in gross field production rates increasing from circa 20 TJ/day to 40-45 TJ/day.

Minor works are now in progress at the onshore Minerva Gas Plant to increase water handling capacity which is expected to facilitate a further short-term production boost late in the March quarter. Minerva contributed 0.87 kbbl of condensate to December quarter production compared with 0.74 kbbl in the previous quarter.

Development

Front end engineering and subsurface studies continue to progress planning for the drilling of a development well in the Henry field, subject to joint venture approval. A pre-FID assurance review was held in October. It is envisaged the development well will be drilled, subject to rig availability, within a future offshore drilling campaign likely late 2020/early 2021.

Exploration

Interpretation of the 3D seismic Quantitative Interpretation inversion volume and re-evaluation of the exploration prospects culminated with two high-graded prospects, Annie and Elanora, being approved by the Joint Venture for drilling in 2019. The prospects are located close to existing offshore production infrastructure with future access to processing and market via the Minerva Gas Plant following its acquisition by the joint venture.

The Annie and Elanora prospects are assessed to have Best Estimate (P50) Prospective Resources of 71 Bcf and 100 Bcf respectively, as announced to the ASX on 8 November 2018[1]. The chance of success (56% at Annie-1 and 44% at Elanora) is considered high as both prospects exhibit seismic amplitudes indicative of the presence of gas. Drilling results at Annie and Elanora have the potential to significantly de-risk the remaining prospect inventory.

The estimated quantities of petroleum that may be potentially recovered by the exploration and application of future development project(s) at Annie and Elanora 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.

Planning and preparations are underway for the drilling of the exploration wells using the Diamond Offshore rig Ocean Monarch, which has been jointly contracted with Esso Australia for a campaign commencing in February 2019. Annie-1 and Elanora-1 are expected to be drilled in the June quarter 2019 following completion of the Esso campaign.

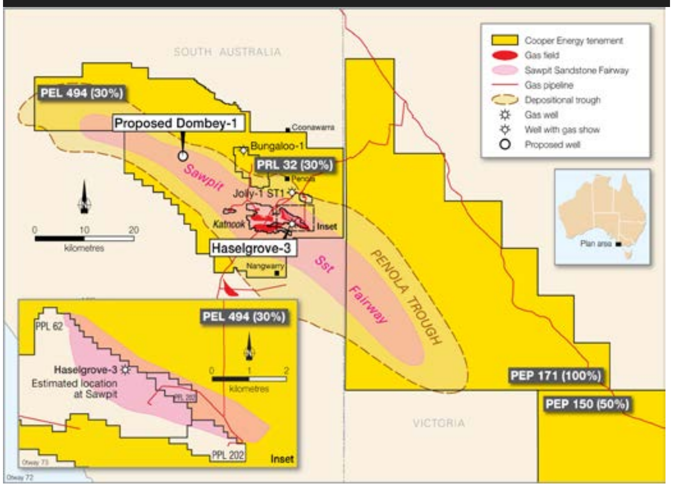
Onshore

Cooper Energy's interests in the onshore Otway Basin include licences in South Australia and permits in Victoria. Activities in the latter are currently suspended pursuant to the moratorium on onshore gas exploration until June 2020 imposed by the Victorian state government.

The onshore Otway interests comprise:

- 30% interests in PEL 494 and PRL 32, South Australia;
- 50% interests in PEP 150 and PEP 168 in Victoria; and
- a 100% interest in PEP 171 in Victoria which may reduce by up to 50% on fulfilment of farm-in arrangements executed with Vintage Energy Ltd.

Onshore Otway Basin, Penola Trough



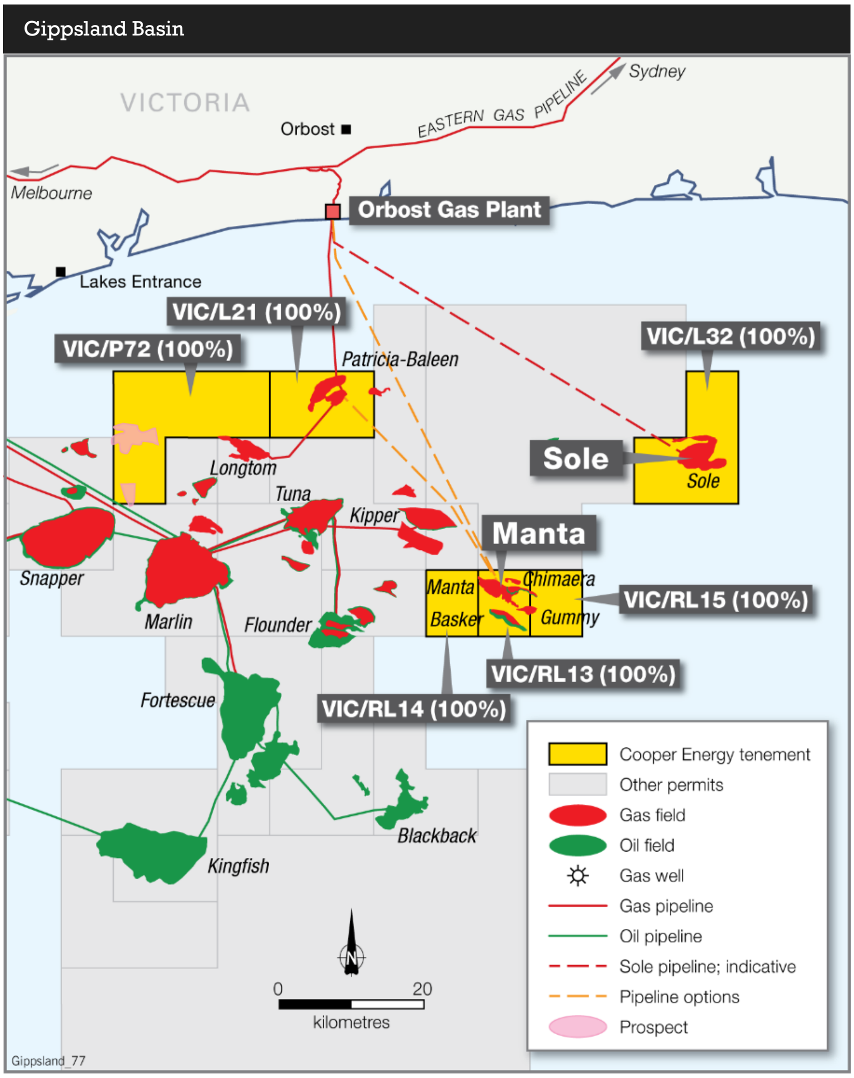
[1] Prospective Resources attributable to the Annie and Elanora prospects were announced to the ASX on 8 November 2018. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply. Refer notes on page 12 for information on calculation.

Spudding of the Dombey-1 exploration well in PEL 494 (Cooper Energy 30%, Beach Energy 70% and Operator) is now expected to occur in the June quarter following re-phasing of the drilling schedule. Dombey-1 is to be located 20 kilometres north-west of the Katnook Gas Plant and will be part-funded through a $6.89 million PACE Gas Round 2 grant by the South Australian Government. The primary targets at Dombey-1 are the Pretty Hill Sandstone and the Sawpit Sandstone, which was confirmed as a viable deep gas exploration target by the discovery at Haselgrove-3 ST1 in PPL 62.

Gippsland Basin

Cooper Energy's interests in the Gippsland Basin include:

1) a 100% interest in, and Operatorship of, production licence VIC/L32, which holds the Sole gas field that is currently under development. Sole is assessed to contain proved and probable reserves of 249 PJ[1] of sales gas;
2) a 100% interest and Operatorship of retention leases VIC/RL13, VIC/RL14 and VIC/RL15 which contain the Manta gas and liquids resource. Manta is assessed to contain Contingent Resources[2] (2C) of 106 PJ of sales gas and 3.2 million barrels of oil and condensate;
3) a 100% interest in, and Operatorship of production licence VIC/L21, which contains the depleted Patricia-Baleen gas field; and
4) a 100% interest in and Operatorship of exploration permit VIC/P72 which was awarded in May 2018.



[1] Reserves attributable to the Sole gas field were announced to the ASX on 29 August 2017. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply. Refer notes on page 13 for information on calculation.

[2] Cooper Energy announced its assessment of the Manta Contingent Resource to the ASX on 16 July 2015. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply. Refer notes at the back of this report for information on calculation.

Development

Sole Gas Project

The Sole Gas Project involves the development of the Sole gas field and upgrade of the Orbost Gas Plant to supply approximately 24 PJ per annum. Approximately 179 PJ of the field's proved and probable gas reserves of 249 PJ have been contracted for sale with the balance retained for future sales contracts.

Cooper Energy is conducting the upstream work to develop and connect the gas field to the Orbost Gas Plant. APA Group is undertaking the upgrade of the Orbost Gas Plant to process gas from Sole.

The upstream project involves the drilling and connection of two near-horizontal production wells, subsea wellheads and connection of the subsea pipeline and control umbilical to the plant via two horizontal drilled shore crossings.

Supply of sales gas from Sole is scheduled to commence in July 2019.

Project progress in December quarter

The offshore project progressed during the quarter to be 86% complete as at 31 December 2018. Capital expenditure incurred on the project by Cooper Energy totaled $281 million to 31 December 2018, with all remaining works to be completed under fixed price-lump sum contracts. This position is within budget for the P50 estimated offshore project cost of $355 million.

Key milestones and progress during the December quarter included:

- **subsea line pipe:** pipelay of 65 km of reeled pipe by the installation vessel Seven Oceans was completed. As advised to the ASX on 12 November and 11 December, hydrotest operations identified an isolated instance of damage and a 20 metre section of pipe was removed. A subsequent hydrotest of the remaining pipeline was performed successfully.
- **control umbilical:** final factory acceptance was completed. The umbilical load out onto the installation vessel, Skandi Acergy, was completed and transportation commenced in readiness for installation.
- **onshore project:** vendor packages continue to be installed at the Orbost Gas Plant, including the first switchgear room, high pressure absorber vessels, flash vessels and ground flare reinstatement.

Further work and schedule

The offshore project is scheduled to be complete and available to supply gas to the plant by the end of May, in advance of the required date for onshore plant commissioning.

The remaining workstreams in the offshore project include repair of the damaged section of pipe, integrity confirmation of the pipeline, final connection and tie-in of the pipeline and control umbilical and final work on the offshore project elements prior to gas flow.

The control umbilical is expected to arrive in Australia in late January, with installation expected to be undertaken in February.

The timelines required for the regulatory permitting and approval of subsea pipeline work mean the pipeline repair is expected to commence in late April and be completed by early May 2019.

Current expectations are the plant will receive the first flow of gas from Sole for commissioning purposes mid-June 2019 with performance testing completed and sales commencing within July.

Manta

The business case for the development of the Manta gas field has been reinforced by gas supply and demand forecasts, customer enquiries, detailed knowledge of cost reductions acquired through conduct of the Sole Gas Project and identification of the synergies available between the Sole and Manta projects.

Current plans include the drilling of an appraisal well, Manta-3, which will also test the Manta Deep exploration prospect. Planning has been initiated for the drilling of Manta-3 within an offshore drilling campaign that, subject to rig availability, could commence in the December quarter 2020.

Exploration

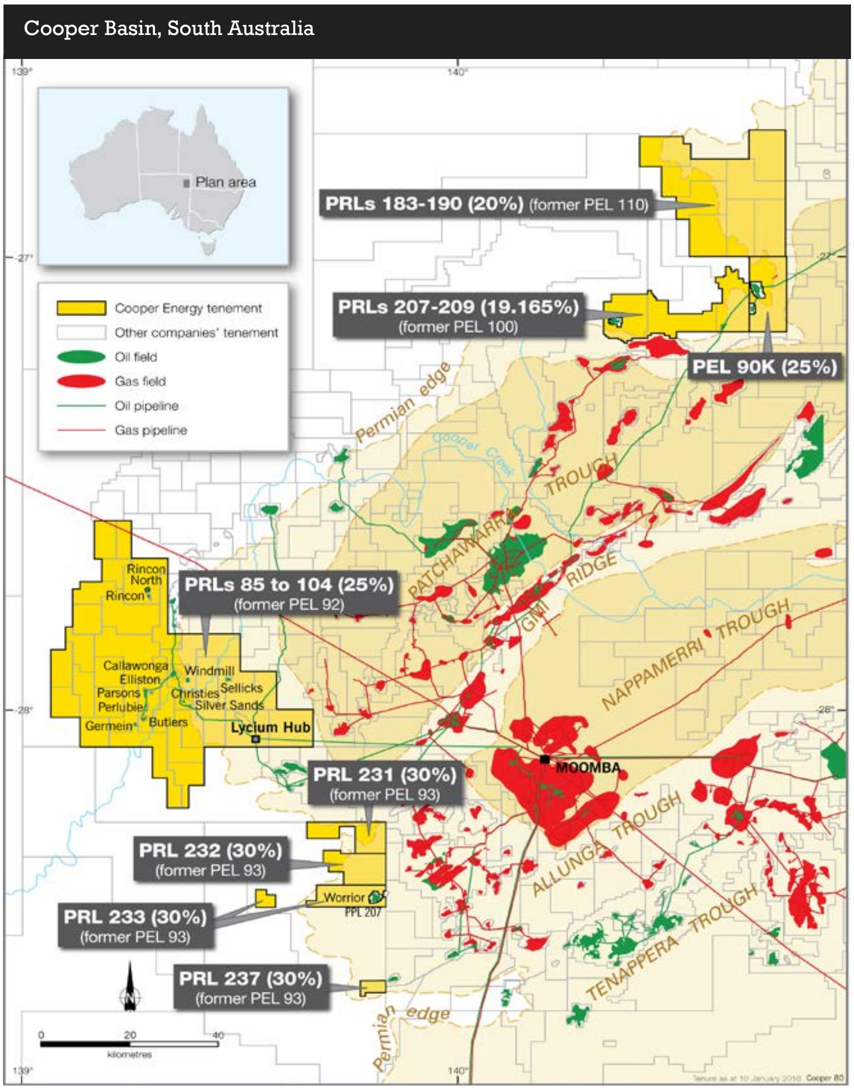
VIC/P72

Acquisition of reprocessed 3D seismic is progressing with preliminary seismic volumes received during the quarter. Seismic interpretation has begun on the preliminary seismic data and a Quantitative Interpretation seismic study initiated. VIC/P72 adjoins the company's VIC/L21 licence which holds the depleted Patricia-Baleen gas field and its associated subsea production infrastructure connected to the Orbost Gas Plant. The permit is in close proximity to several Esso-operated gas and oil fields including Snapper, Marlin, Sunfish and Sweetlips and the Longtom gas field operated by SGH Energy. Prospect analogues similar to the offset fields are identified in VIC/P72.

Cooper Basin

The company's Cooper Basin interests during the quarter comprised:

1) a 25% interest in the oil-producing PEL 92 Joint Venture which holds the PRLs 85 -104 on the western flank of the Cooper Basin and production licences within this region. The PEL 92 Joint Venture accounted for approximately 96% of the company's oil production for the quarter;
2) a 30% interest in the oil producing PPL 207 ('Worrior') Joint Venture and PRL's 231, 232, 233 and 237 on the western flank of the Cooper Basin; and
3) interests in northern Cooper Basin exploration licences PEL 90K, PRLs 183 - 190 and PRLs 207 – 209.



Production

Cooper Energy's share of oil production from its Cooper Basin tenements for the December quarter was 58.8 kbbl (average 636 bopd) compared with 61.2 kbbl (average 666 bopd) in the previous quarter. The 4% quarter-on-quarter reduction was a result of natural field decline.

Production attributable to Cooper Energy's interest in the PEL 92 Joint Venture in the December quarter accounted for 56.5 kbbl of oil representing an average daily rate of 615 bopd. In comparison, production from PEL 92 averaged 640 bopd in the previous quarter and 782 bopd in the December quarter FY18.

Production from the PPL 207 Joint Venture (Worrior oil field) accounted for the balance of the company's Cooper Basin production. Cooper Energy's share of PPL 207 December quarter production was 2.2 kbbl, compared to 2.4 kbbl in the previous quarter.

Exploration and Development

Reprocessing and merging of the Caseolus, NMC and Rincon 3D seismic surveys in PEL 92 was completed in the quarter. The results of this activity will assist future definition of exploration prospectivity. The PEL 92 Joint Venture is considering drilling up to 3 appraisal wells on the Parsons field in the June quarter 2019. In PRL 231, 232 and 233, formerly PEL 93, preparations are underway to acquire the Westeros 3D seismic survey which is scheduled to commence in early 2019.

Terms and abbreviations

Cooper Energy reports uses terms and abbreviations common to the petroleum industry and the financial sector.

Terms used include:

- 2C: Best Estimate, contingent resources
- 2D, 3D: two dimensional, three dimensional (with respect to seismic surveys)
- 2P: proved and probable reserves
- bbl: barrels
- Bcf: Billion cubic feet (of gas)
- bfpd: barrels of fluid per day
- bopd: barrels of oil per day
- Casino Henry: Casino Henry Netherby
- Cooper Energy: Cooper Energy Limited and/or its subsidiaries
- FEED: Front End Engineering and Design
- FID: Final Investment Decision
- Financial year: 12 months ending 30 June
- HDD: Horizontally directional drill
- JV: Joint Venture
- kbbl: thousand barrels
- km: kilometres
- m: metres
- MM: million
- MMboe: Million barrels of oil equivalent
- MMscf/day: Million standard cubic feet per day
- MDRT: measured depth rotary table
- n/m: not meaningful
- pcp: prior corresponding period
- PEL: Petroleum Exploration Licence
- PEP: Petroleum Exploration Permit
- PJ: petajoules
- PRL: Petroleum Retention Licence
- PPL: Petroleum Production Licence
- the quarter: three months ended 30 December
- SPE: Society of Petroleum Engineers
- spudding: the commencement of drilling a petroleum well
- TJ: Terajoules

Disclaimer and explanatory notes

Disclaimer

The information in this report

- Is not an offer or recommendation to purchase or subscribe for shares in Cooper Energy Limited or to retain or sell any shares that are currently held.
- Does not take into account the individual investment objectives or the financial situation of investors.
- Was prepared with due care and attention and is current at the date of the report.
- Actual results may materially vary from any forecasts (where applicable).
- Before making or varying any investment in shares of Cooper Energy Limited, all investors should consider the appropriateness of that investment in light of their individual investment objectives and financial situation and should seek their own independent professional advice.

Hydrocarbon Reporting Standard

Cooper Energy reports hydrocarbons in accordance with the SPE Petroleum Resources Management System 2007 (SPE-PRMS).

Calculation of Reserves and Contingent and Prospective Resources

Cooper Energy has completed its own estimation of reserves and resources in its Operated permits and for non-operated permits based on information provided by the permit Operators Beach Energy Ltd, Senex Ltd, Santos Ltd, and BHP Billiton Petroleum (Victoria) P/L in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2007 Petroleum Resources Management System (PRMS). Petroleum reserves and resources estimates are prepared by deterministic and probabilistic methods. The resources estimate methodologies incorporate a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes. Project and field totals are aggregated by arithmetic summation by category. Aggregated 1P, 1C and Low (P90) estimates may be conservative, and aggregated 3P, 3C and High (P10) estimates may be optimistic due to the effects of arithmetic summation.

Reserves

Under the SPE PRMS, reserves are those petroleum volumes that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

The Otway Basin totals comprise the arithmetically aggregated project fields (Casino-Henry-Netherby and Minerva) and exclude reserves used for field fuel.

The Cooper Basin totals comprise the arithmetically aggregated PEL 92 project fields and the arithmetic summation of the Worrior project reserves, and exclude reserves used for field fuel.

The Gippsland Basin total comprise Sole field only. A revised reserves assessment to reflect the reclassification of Sole gas from contingent resources was announced to the ASX on 29 August 2017.

Contingent Resources

Under the SPE PRMS, contingent resources are those petroleum volumes that are estimated, as of a given date, to be potentially recoverable from known accumulations but for which the applied projects are not considered mature enough for commercial development due to one or more contingencies.

The contingent resources assessment includes resources in the Gippsland, Otway and Cooper basins. The following contingent resources assessments have been released to the ASX:

- Manta Field on 16 July 2015; and
- Basker and Manta fields on 18 August 2014.

Cooper Energy is not aware of any new information or data that materially affects the information provided in those releases, and all material assumptions and technical parameters underpinning the estimates provided in the releases continue to apply.

Contingent and Prospective Resources have been assessed using deterministic simulation modelling and probabilistic resource estimation for the Intra-Latrobe and Golden Beach Sub-Group in the Manta field. This methodology incorporates a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes. The conversion factor of 1 PJ = 0.163 MMboe has been used to convert from Sales Gas (PJ) to Oil Equivalent (MMboe) from the September quarter 2018, as first advised on 13 August 2018 in the announcement of reserves and resources at 30 June 2018. Total production in prior periods is reported in MMboe as previously reported and calculated using the conversion factor 1 PJ = 0.172 MMboe. Contingent Resources for the Manta Field have been aggregated by arithmetic summation.

Prospective Resources

Under the SPE PRMS, Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Cooper Energy has undertaken a Prospective Resources assessment using probabilistic resource estimation for the Waarre Formation in the Annie and Elanora prospects. This methodology incorporates a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes. This approach is consistent with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2007 Petroleum Resources Management System (PRMS). Analytical procedures used to assess Prospective Resources were:

- interpretation of reprocessed 3D seismic data;
- detailed seismic time to depth conversion; and
- wireline log correlation and petrophysical analysis from the wells drilled in the adjacent fields;

The date of this Prospective Resource assessment is 7 November 2018.

Cautionary Statement: The estimated quantities of petroleum that may be potentially recovered by the application of 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.

Rounding

Numbers in this presentation have been rounded. As a result, some total figures may differ insignificantly from totals obtained from arithmetic addition of the rounded numbers presented.