

FY19 First half results & outlook

Investor presentation 11 February 2019



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P50 as it relates to costs is best estimate; **P90** as it relates to costs is high estimate

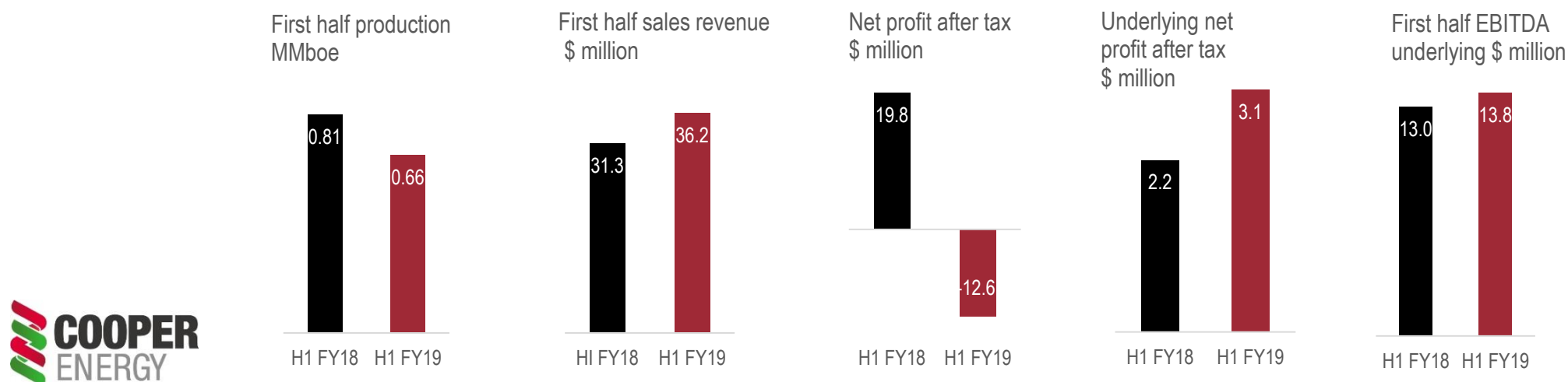
Features of FY19 First half

1. Sole project performance: taken to 86% complete and within budget.
2. Finance position strengthened: funds released and available after redetermination.
3. Gas contracting stepping up: new Otway contracts in first half to be followed by new contract signings in second half.
4. Going for the next wave: rig commitment to drill low risk/high value offshore Otway gas exploration targets from May 2019.

FY19 First half key outcomes

Gas revenue growth; Sole advancing, within budget; Otway gas exploration accelerated into FY19

- HSEC: zero recordable injury cases and zero reportable environmental incidents
- Sole Gas Project: 86% complete, within budget and within schedule for gas to plant in June
- New gas contracts and prices for Casino Henry supply from 1 January 2019
- Finance facility redetermination which recognises Sole Gas Project cost outlook and adds to available funds
- Completion of offshore Otway Basin geo-tech assessment, announcement of prospective resources
- Contracting of Diamond Offshore Ocean Monarch for Otway Basin gas exploration in June quarter 2019
- Production of 0.66 MMboe vs 0.81 MMboe in pcq
- Sales revenue up 16% to \$36 million
- Statutory net loss after tax of \$(12.6) million vs PCP statutory profit after tax of \$19.8 million
- Improvement in EBITDA and underlying profit



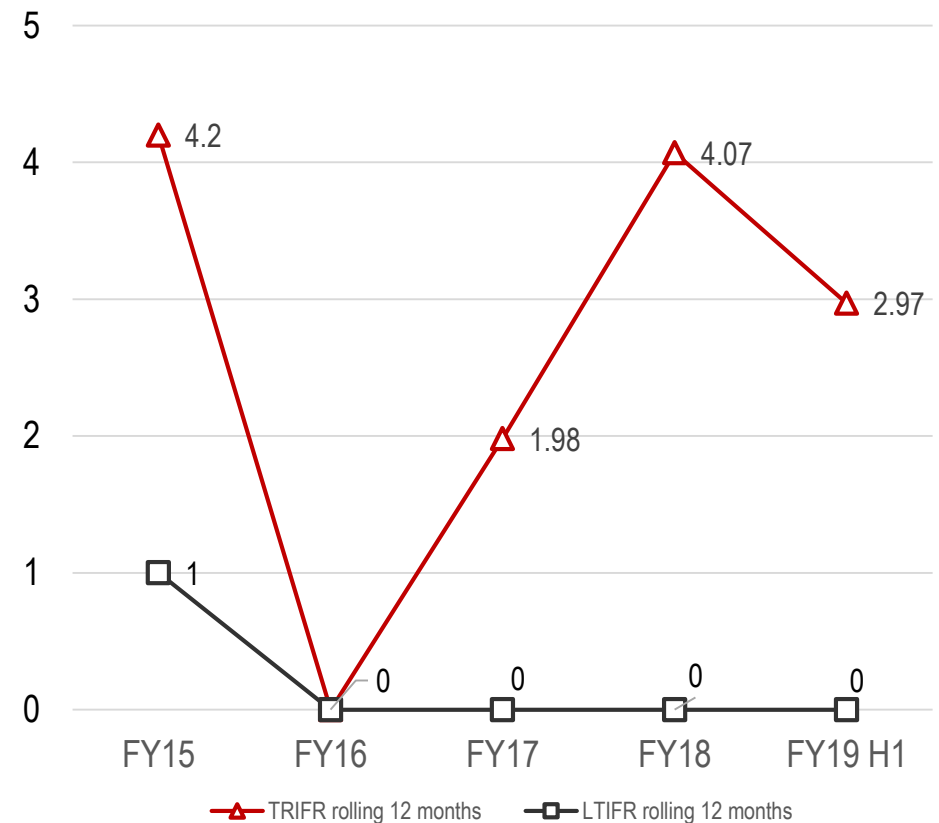
Health Safety Environment Community (HSEC)

Injury and incident free. Operator management systems developed and implemented plus ongoing improvement program driven by value of Care.

- **TRIFR = 2.97 (FY18 TRIFR = 4.07)**
- **Zero Lost Time Injuries**
- **Compliance as a new offshore Operator**
 - HSEC Management Systems: developed and fit-for-purpose
 - Ongoing refinement of regulatory plans and management system based on lessons learnt
- **Improvements and Initiatives:**
 - “Care”: a core value
 - Implementation of systems to improve the tracking of risks and actions
 - Ongoing emergency response arrangements awareness and training
 - a “One Team” culture

Safety performance

Total recordable injury and lost time injury frequency rates



Key financial results

<i>\$ million unless otherwise indicated</i>	H1 FY19	H1 FY18	change	
Production MMboe	0.66	0.81	▼	-15%
Sales revenue	36.2	31.3	▲	16%
Gross profit	16.7	14.1	▲	18%
Gross profit/Sales revenue %	46.1	45.0%	▲	2%
Statutory profit before tax	(10.4)	14.1	▼	-173%
Statutory profit/(loss) after tax	(12.6)	19.8	▼	-164%
Underlying EBITDA	13.8	13.0	▲	6%
Underlying profit/(loss) after tax	3.1	2.2	▲	41%
Cash flow from operations	(1.6)	10.0	▼	- 116%
	31 Dec 18	30 June 18		
Drawn debt	186.4	125.9	▲	48%
Cash	193.9	236.9	▼	-18%
Net cash (debt)	7.5	111.0	▼	-93%

Statutory and underlying profit

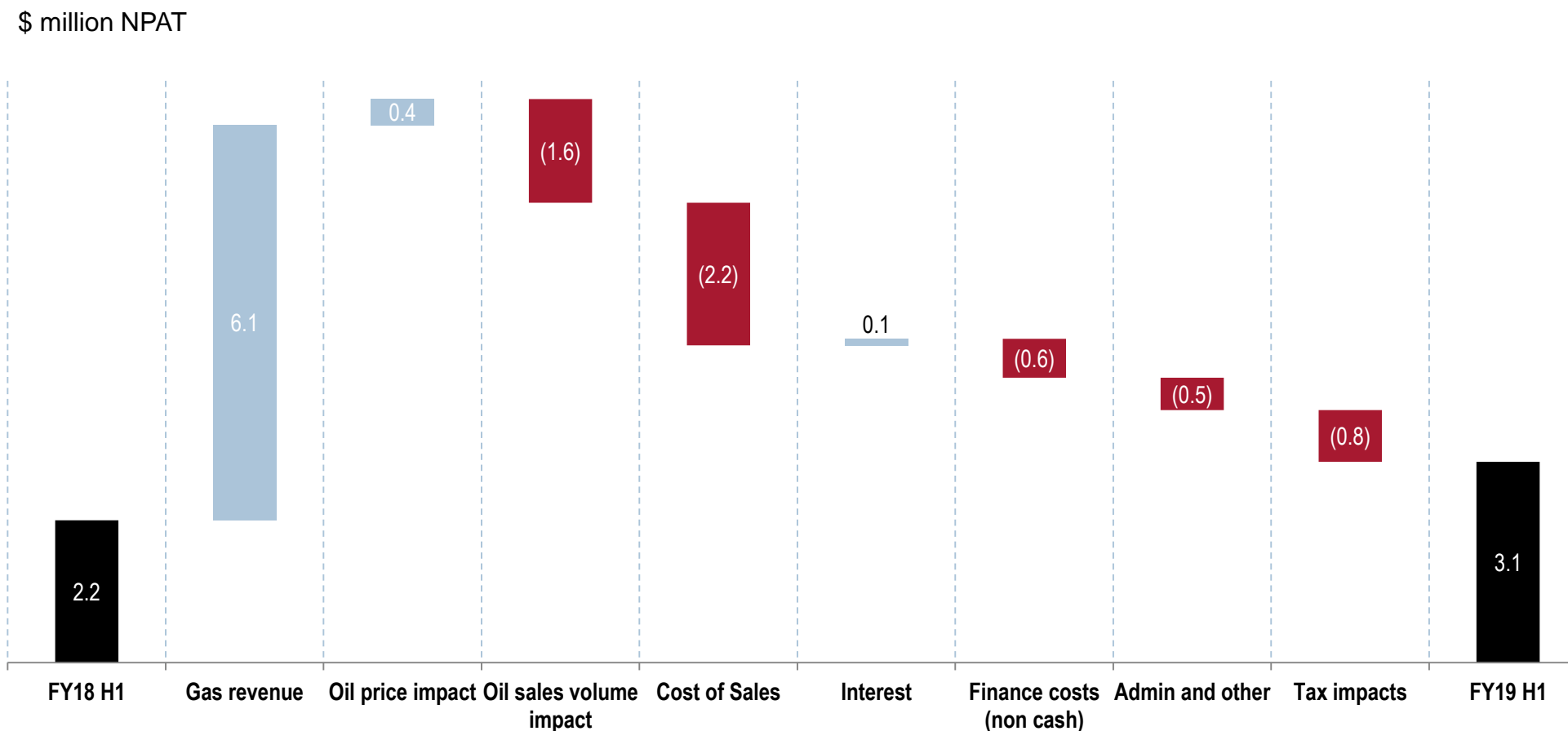
Restoration expense the principal significant item

<i>6 months ending 31 December 2018:</i>	<i>\$ million</i>
Net profit after tax	(12.6)
Adjustments for:	
Exit provision gain, Tunisia	(0.8)
Restoration expense	16.5
Tax impact	-0.2
Underlying net profit after tax	3.1

- Significant item \$(16.5) million for Restoration Expense arising from reassessment of rehabilitation provision for Patricia Baleen gas field

First half underlying NPAT movement

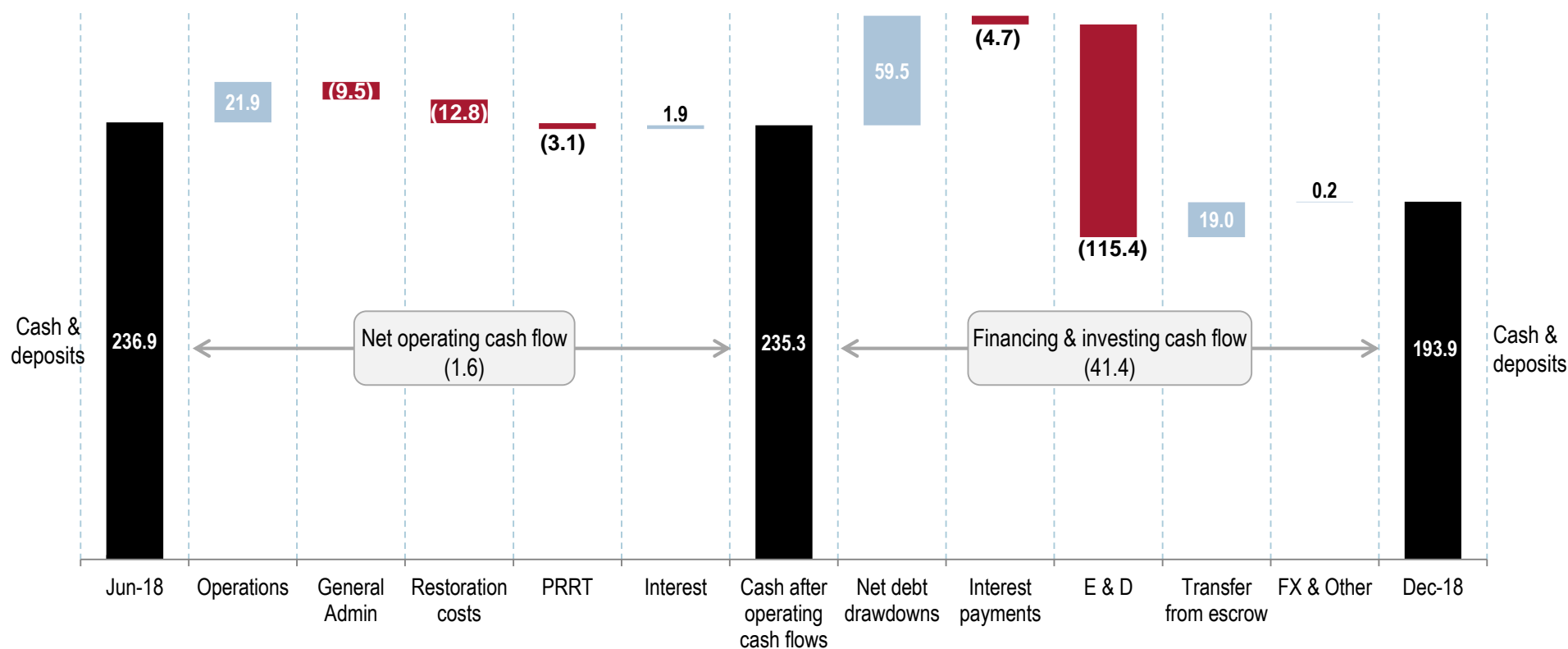
Higher gas revenue the major factor in higher underlying profit



Movement in cash

Operating cash flow impacted by restoration costs, cash applied to capex

\$ million



- Cash expenditure on restoration cost of \$12.8 million includes abandonment of Sole-2 and expenditure on BMG
- Cash expenditure on general admin includes STIP payments

Funding

Redetermination released funds and increased available debt

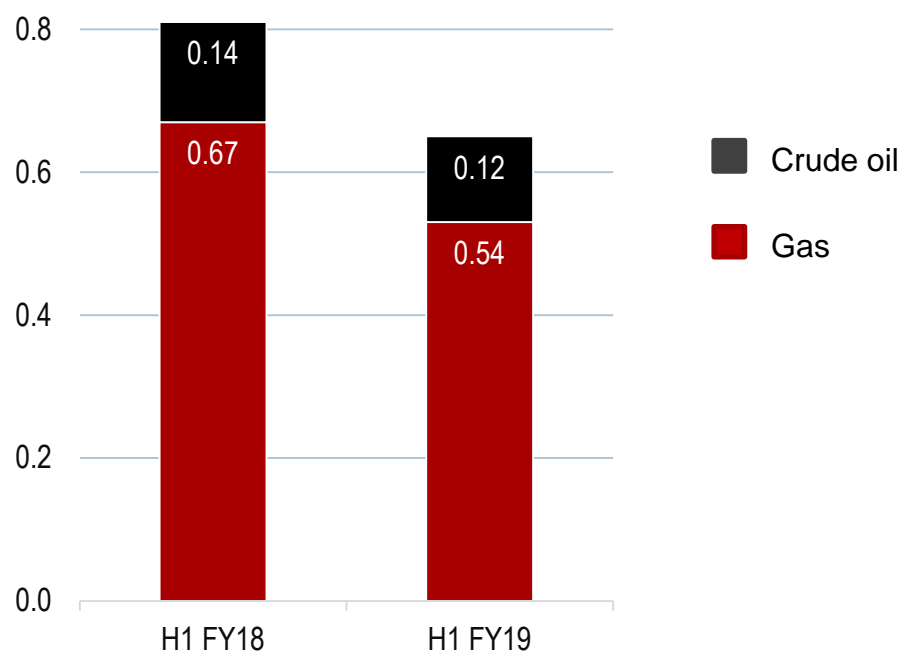
- Redetermination of project finance facility which recognises Sole project performance and outlook
- Variations to key terms include:
 - facility to fund 60% of Sole development costs (previously funded 55% of Sole development costs)
 - facility now assumes financiers' total project cost of \$369 million (previously \$395 million)
 - release of \$23.3 million in surplus equity (cash) for general corporate purposes otherwise earmarked exclusively for Sole development costs
- Increase in available cash to be used in support of offshore Otway Basin gas exploration planned for FY19 H2

<i>\$ million</i>	31 Dec 18	30 Jun 18
Cash	193.9	236.9
Drawn debt	186.4	125.9
Debt available		
• Project facilities	46.6	98.9
• Working capital	14.1	14.1

Production and sales generation

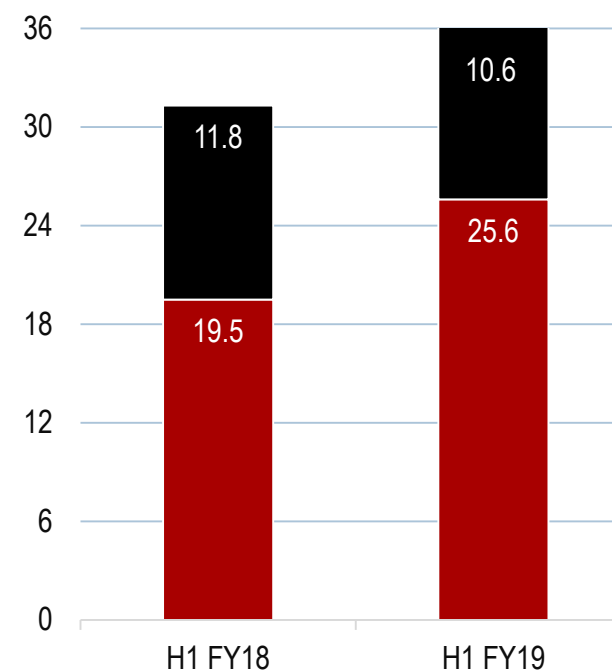
Growth in gas sales revenue

Production
MMboe



- Gas:
 - Casino Henry shutdown
 - Minerva approaching end of life
- Oil: Cooper Basin natural decline

Sales revenue
\$ million



- New 2018 gas contracts
- Higher oil prices

Review of operations: offshore Otway Basin

Sales under FY18 contracts, new contracts secured for FY19

Casino Henry

- Lower first half production due to scheduled maintenance shutdown & Netherby-1 shut-in
- new gas contracts at 2018 prices
- new gas contracts secured for FY19

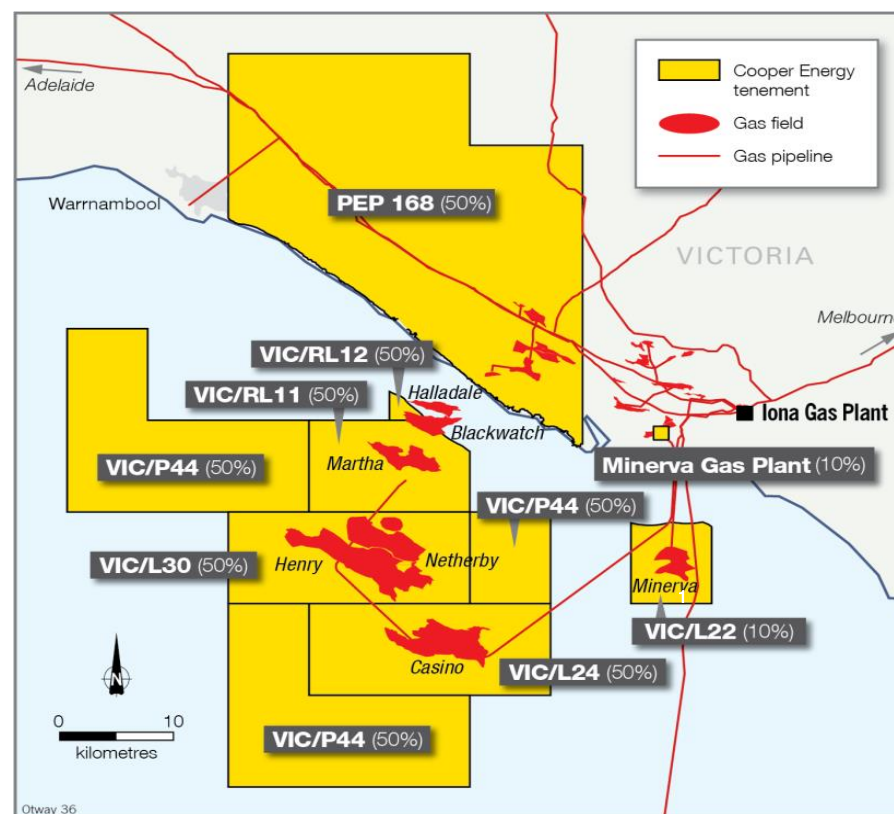
Minerva gas field

- approaching end of field life

Exploration

- Geotechnical modelling and analysis completed; prospects identified and ranked
- Prospective resources announced for drill targets Annie & Elanora

First half production	H1 FY19	H1 FY18
Sales gas PJ	3.28	3.87
Condensate kbbl	2.4	3.6



Sole Gas Project

86%¹ complete, \$281 million incurred and within budget. On schedule for gas to plant in June.

Offshore project

Shore Crossing



✓ **Completed**

Production wells



✓ **Completed**

- Gas composition confirmed
- Reservoir to expectations
- Production upside potential

Umbilical



□ **To be completed:**
March 2019

- ✓ Final factory acceptance
- Lay and trenching underway

Pipeline



□ **To be completed:**
May 2019

- ✓ 65 km pipe laid & hydrotest
- Repairs to isolated section
- Final testing

Onshore (APA)

Orbost Gas Plant



□ **To be completed:**

- Field gas to plant mid-June
- Commissioning gas sales July
- Performance test to commence July
- Completion

Offshore project complete, available to supply Orbost Gas Plant by end May 2019

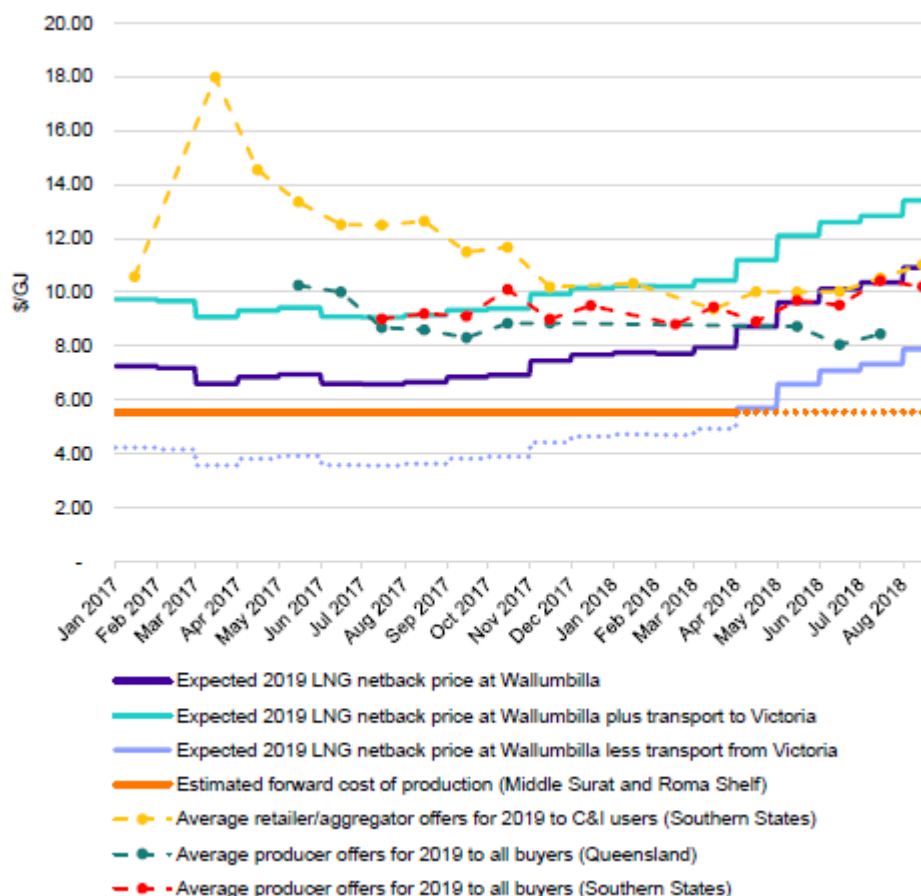
Firm gas supply commences

¹ As at 31 December 2018

Southern states gas prices: ACCC view

Gas price and LNG netback trend

Average monthly commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (southern states)



2019 expected prices

Expected 2019 wholesale gas commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2017 and 30 August 2018)

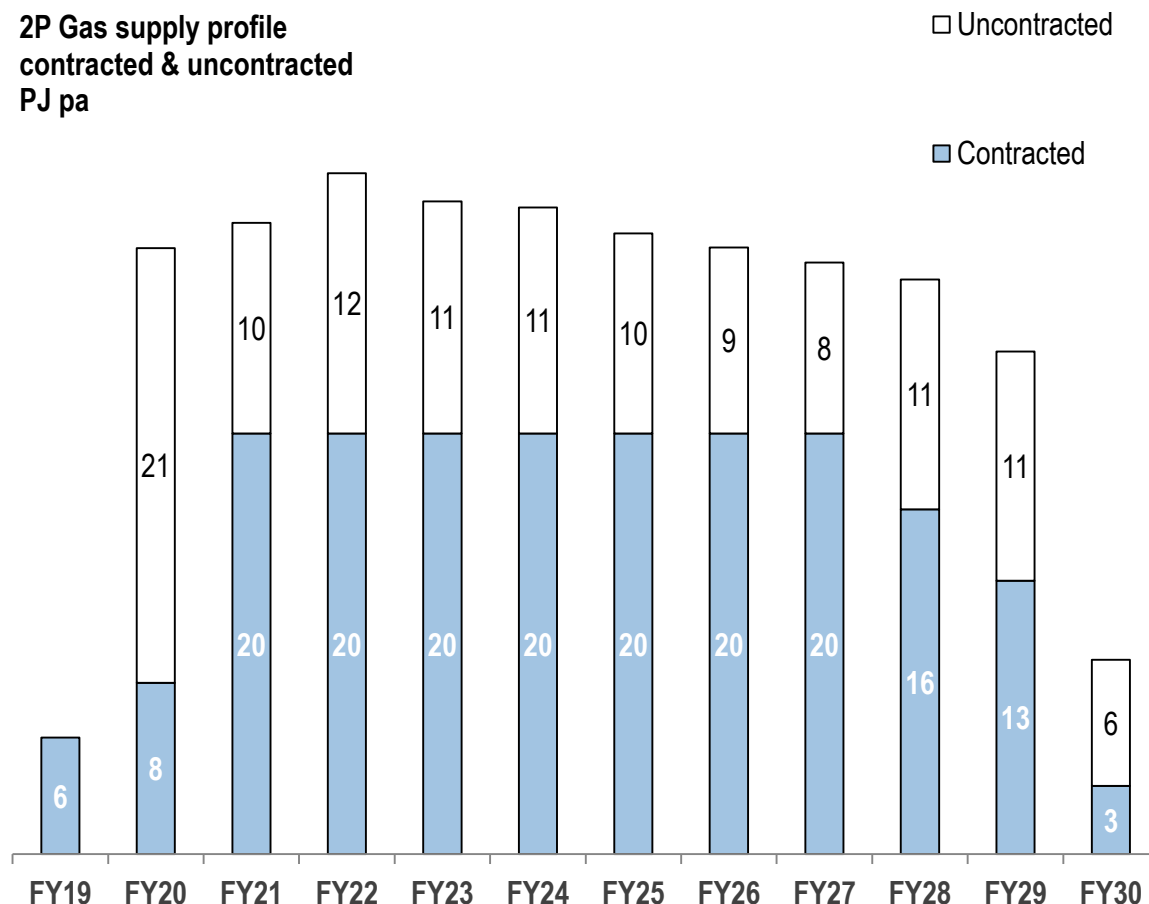
Expected 2019 wholesale gas commodity prices*	Avg price \$/GJ	Price range \$/GJ
Producers (Vic only)	9.72	9.31 – 10.71
Producers (Vic & SA)	9.37	8.71 – 10.71
Producers (QLD)	8.36	7.63 – 8.52
Retailer/aggregator (Vic)	10.66	9.00- 12.51

Source: ACCC Gas Inquiry 2017 – 2020 Interim Report December 2018
Based on contract information provided to ACCC

Gas marketing

120 PJ of uncontracted 2P reserves remains available to market

- First phase of FY19 gas marketing plans completed:
- 12 month contracts with Origin Energy and O-I from 1 January 19
- Second phase initiated: negotiating sale of other uncontracted gas with particular focus on FY20 to FY21
- Strong response from industrial and utility gas customers
- Expect to secure contracts in H2 FY19



Note

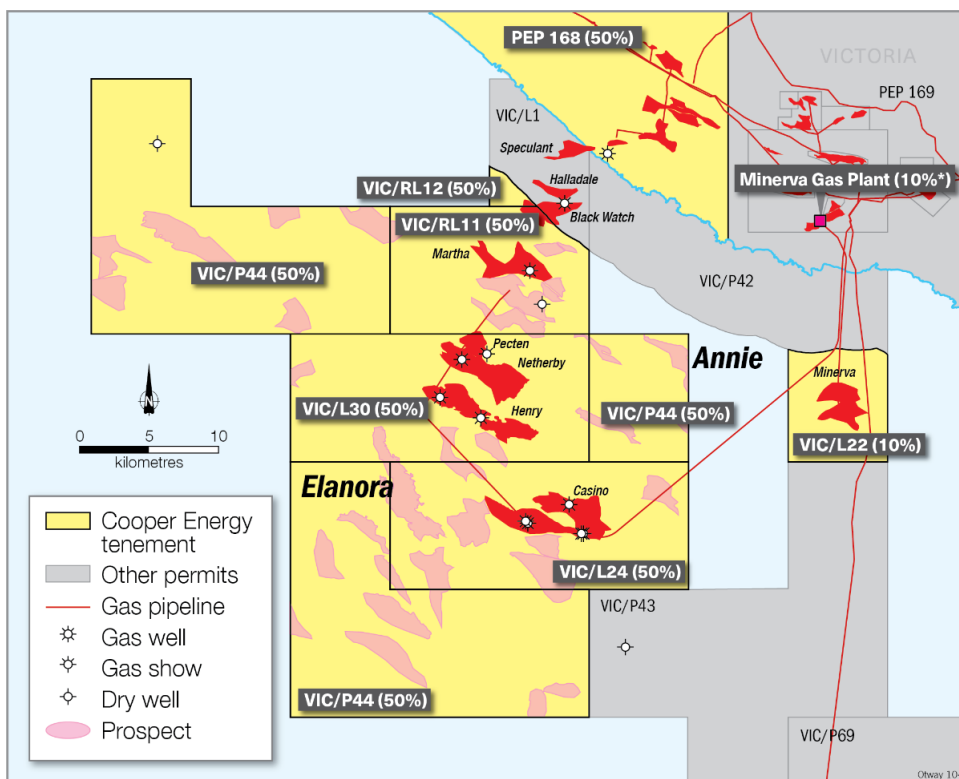
1. Assumes:

- Sole sales from July 2019 which is subject to completion and Orbest Gas Plant availability. Sole daily production rate assumed is 68 TJ/day.
- Henry development well Dec 20 – Feb 21, subject to rig availability & JV approval
- No exploration success

2. All numbers rounded and Cooper Energy equity share

Offshore Otway Basin exploration

Prospect rich and favourable economics due to pipeline and plant access
Seismic inversion and subsequent studies identified 2 leading candidates for drilling



Gross unrisked Prospective Resource²
(billion cubic feet, Cooper Energy share 50%)

Prospect	Low (P90)	Best (P50)	High (P10)
Annie	36.2	70.5	137.0
Elanora	33.9	100.1	284.8
Total	70.1	170.6	421.8

Unrisked Prospective Resource² net to Cooper Energy
(billion cubic feet)

Prospect	Low (P90)	Best (P50)	High (P10)
Annie	18.1	35.3	67.5
Elanora	16.9	50.0	142.4
Total	35.0	85.3	210.9

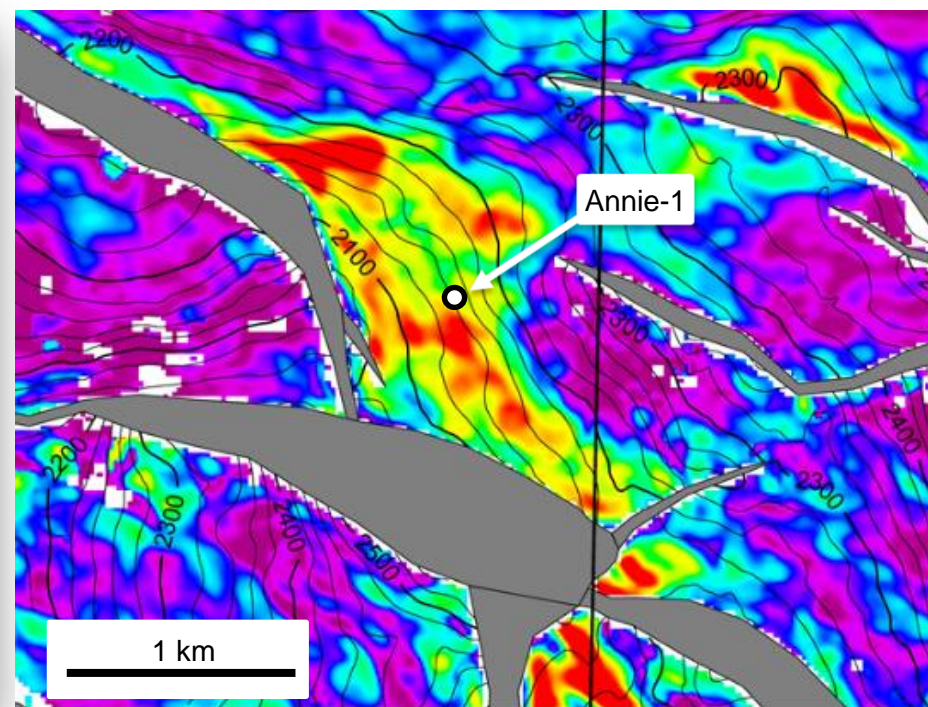
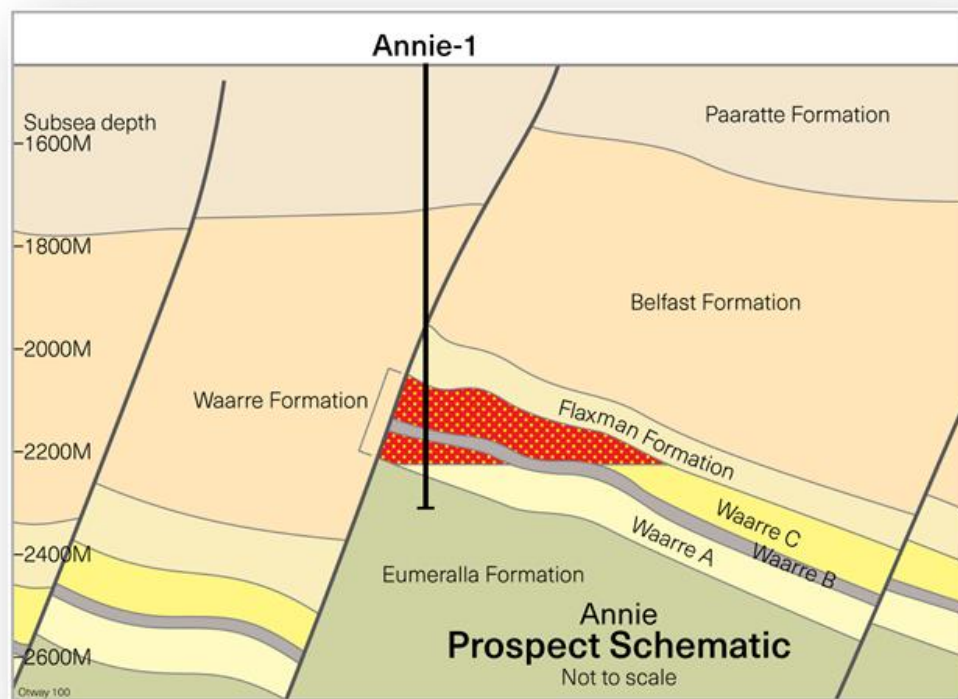
The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration, appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

¹ As announced to the ASX today 8 November 2018. Cooper Energy confirms that it is not aware of any new information or data that materially affects the information included in the announcement and that all the material assumptions and technical parameters underpinning the estimates in the announcements continue to apply and have not materially changed.

Annie prospect

Annie-1 is low risk and well defined

- Subsurface / structure well defined on 3D seismic data
- Faulted '3-way' dip closure with well defined seismic amplitude 'anomaly' and seismic inversion (QI) gas indicator
- High historical success rate (>80%) in Otway for wells drilled on anomalies
- High quality Waarre C primary reservoir target (same as Minerva and Casino-5)
- High deliverability production wells, simple development to pipeline tie-in 10km south
- Success de-risks several adjacent prospects with similar resource potential

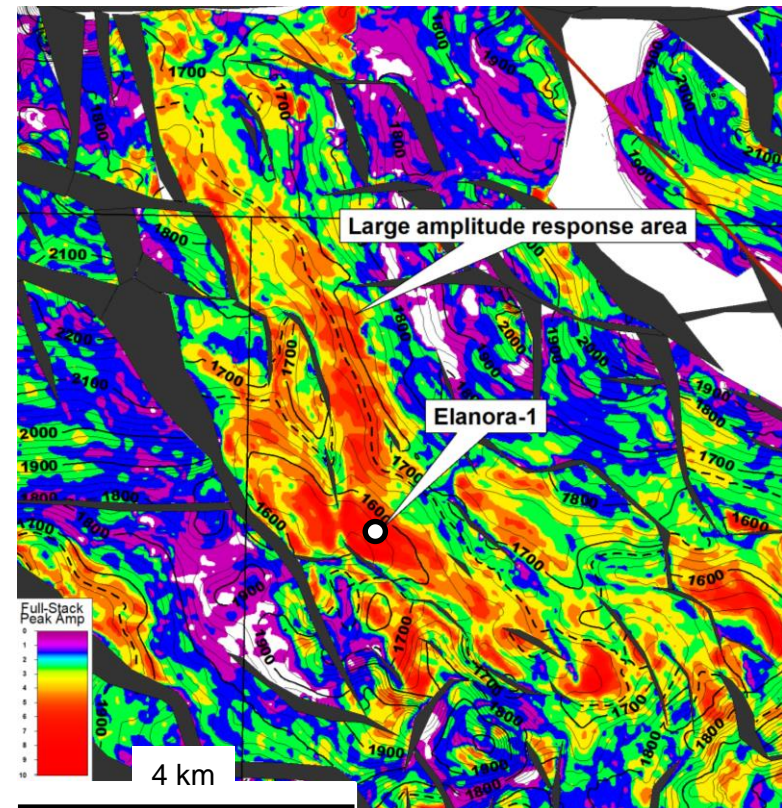
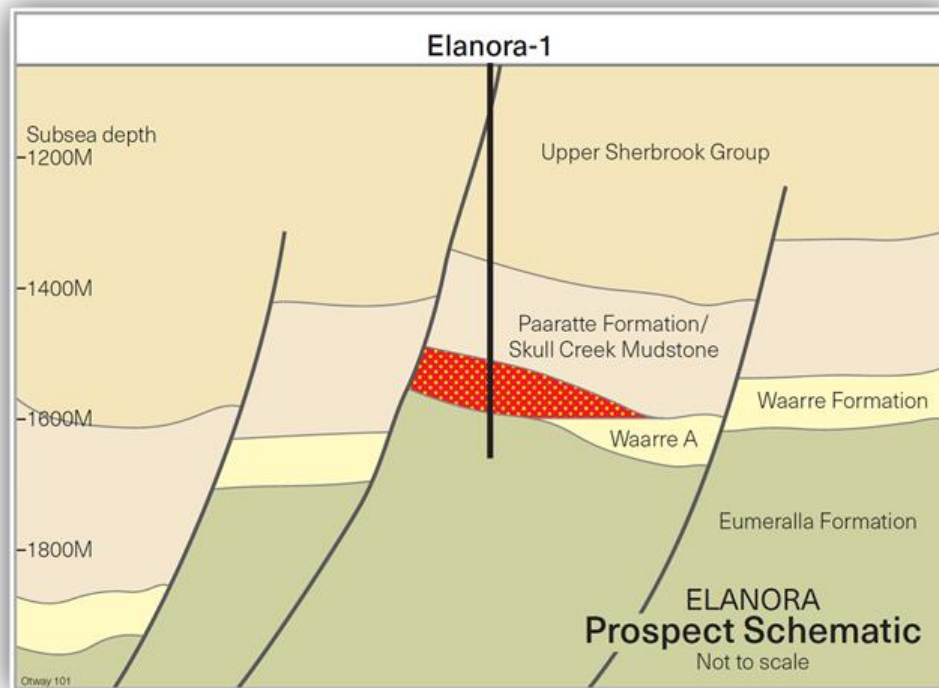


Top Waarre Formation depth structure map highlighting seismic amplitude anomaly

Elanora prospect

Elanora-1 is a strategic well with large upside potential

- Subsurface / structure well defined on 3D seismic data
- Faulted '3-way' dip closure with well defined seismic amplitude 'anomaly' and seismic inversion (QI) gas indicator
- High quality Waarre A primary reservoir target (same as Casino-4, Henry and Netherby fields)
- High deliverability production wells, simple development to pipeline tie-in 7km north east
- Success extends prospects fairway south of current 'known' area and de-risks several large adjacent prospects

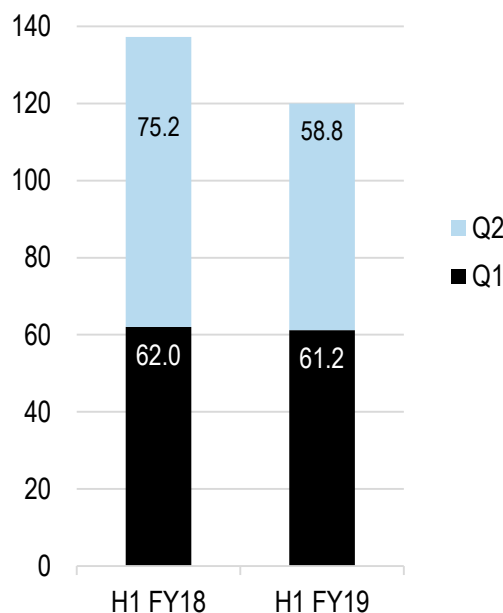


Top Waarre Formation depth structure map and seismic amplitude anomaly

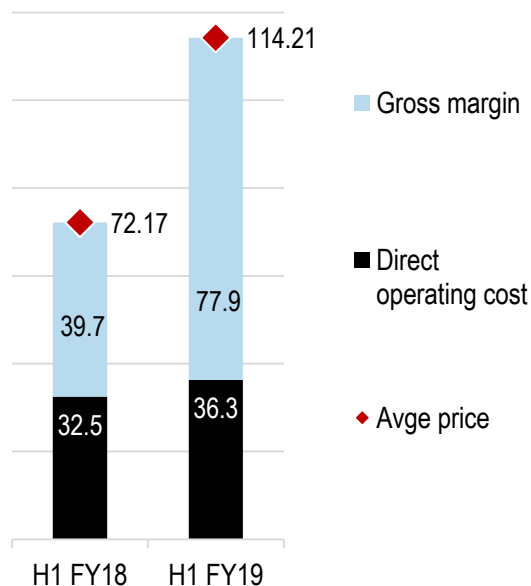
Review of operations: Cooper Basin

Low cost, cash-generating oil production

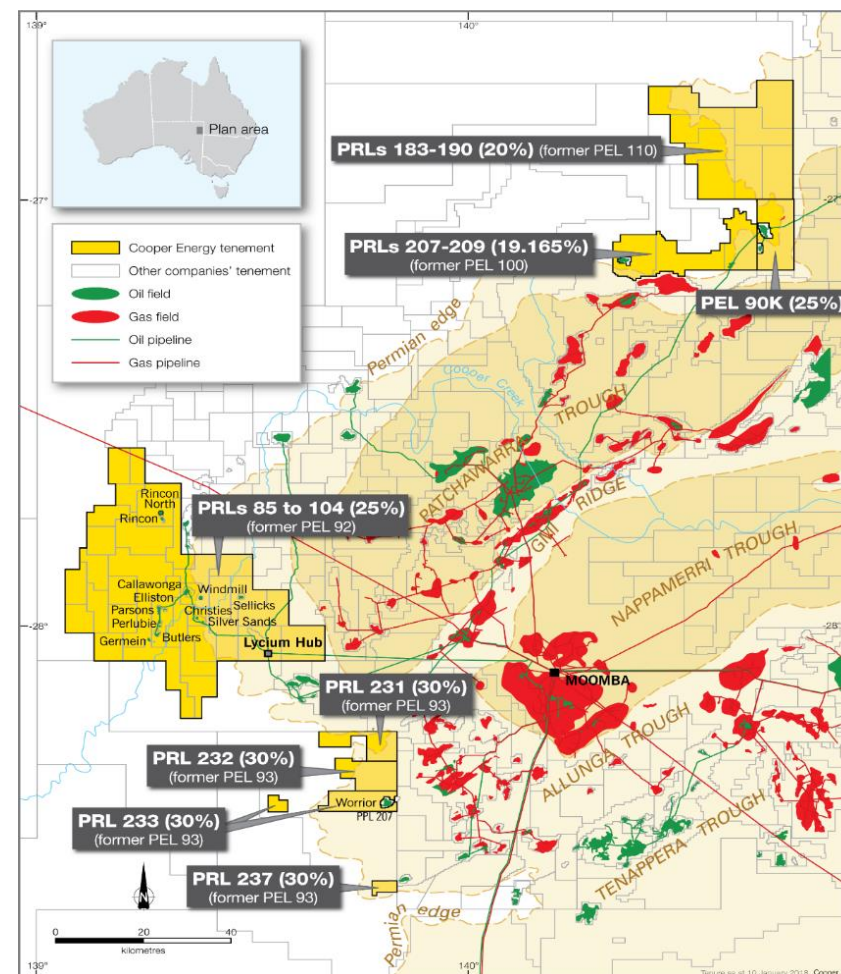
Cooper Basin oil production
kbbbl



Cooper Energy first half oil price cost & margin
AUD/bbl

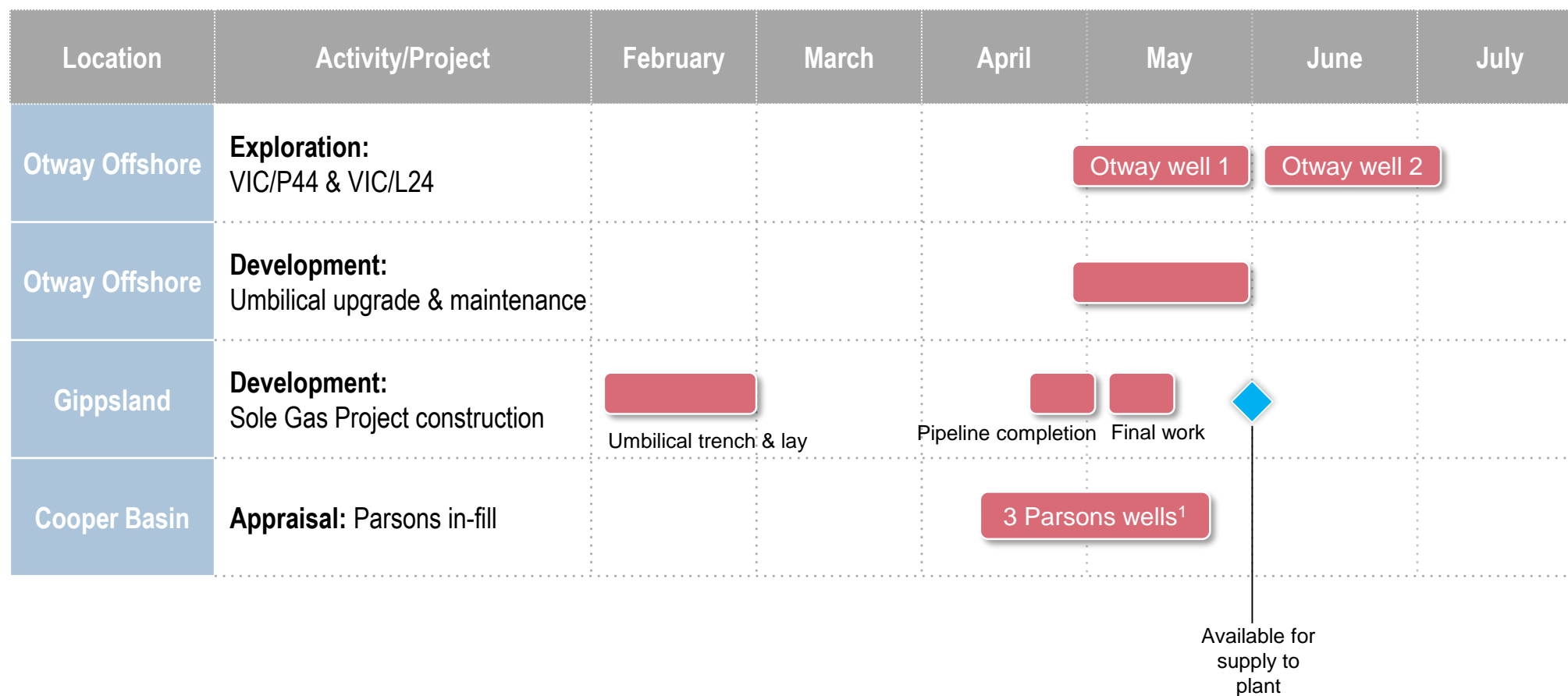


- First half production of 120 kbbbl vs 137 kbbbl in pcip
- PEL 92 Joint Venture: Reprocessing and merging of 3D seismic surveys to aid future prospect definition: Caseolus, NMC and Rincon surveys
- Parsons appraisal drilling planned for H2 FY19 (subject to JV approval)
- PRL 231, 232 and 233: preparations for Westeros 3D seismic survey



FY19 second half drilling and development

Sole moving to completion. Gas exploration drilling offshore and onshore

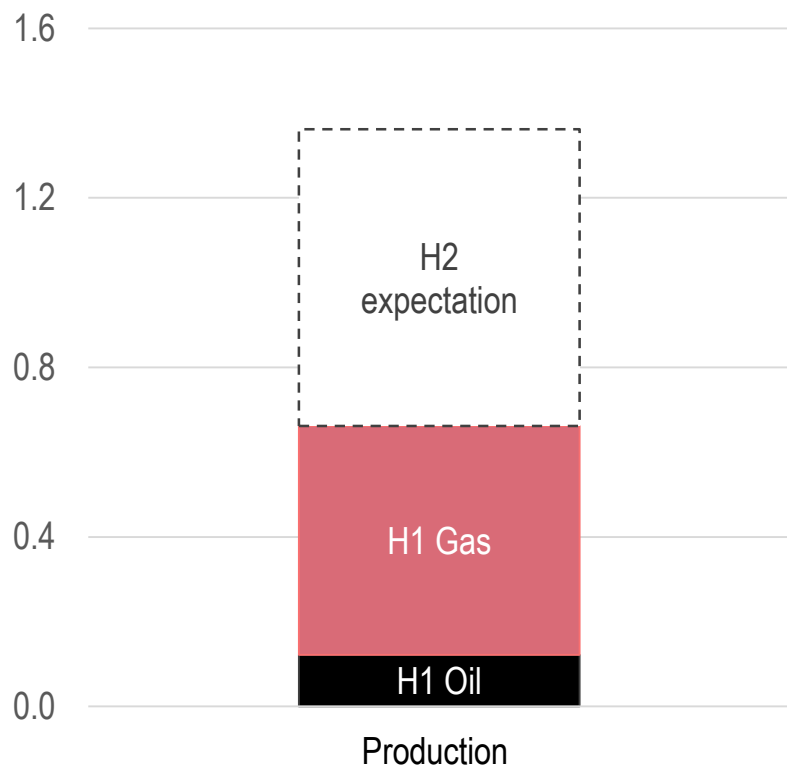


FY19 Production outlook

Higher production expected in second half

FY19 production

MMboe, first half actual and second half expectation



Factors in second half production

- Minerva: 6 month contribution assumed
- Control umbilical upgrade; 3 week shutdown, collaboration with Lochard Energy to coincide with Iona scheduled maintenance for maximum uptime
- Flush production following umbilical repair
- Sole commissioning gas; not included in guidance

Projects pipeline`

5 year development program that can lift gas production more than 10 times FY19 levels

FY19	FY20	FY21	FY22	FY23	FY24
Sole construct	Sole: ¹ production 68TJ/d (~24 PJ per annum)				
	Minerva Gas Plant: ² acquire, integrate and operate				
		Henry³ development well: production uplift			
			Potential offshore Otway production⁴ Production from FY19 exploration		
				Manta⁵ 24 PJ pa plus liquids	

¹ Sole gas field scheduled to supply gas to Orbost Gas Plant from June 2019

² Minerva Gas Plant: Casino Henry JV have agreement to acquire on cessation of Minerva production

³ Henry development well: subject to joint venture FID to access 26 PJ undeveloped 2P reserves

⁴ Offshore Otway: potential development from exploration success in FY19 drilling subject to rig availability and JV approval

⁵ Manta: subject to appraisal well planned for 2020/21 subject to rig availability

FY19 First half wrap-up

1. Exposure to gas markets through contract pricing and uncontracted gas is adding value.

- First half revenue benefitted from alignment of pricing from historical to 2018 contracts
- New gas contracts secured for 2019 and commenced 1 January
- More to come: discussions advancing on contracts from Sole start-up and beyond

2. Sole project performance has start-up in sight and increased funds available for growth.

- First half saw completion of production wells, project passage to 86% complete and within budget
- Redetermination recognises cost performance and outlook has freed funds to apply to next wave of growth after Sole
- Coming 5-6 months to see offshore project completed, gas flow to plant and sales commence

3. Geo-technical and commercial work has Cooper Energy positioned for next wave value opportunities starting in May and extending for several years.

- Offshore Otway drilling from May
- Minerva Gas Plant



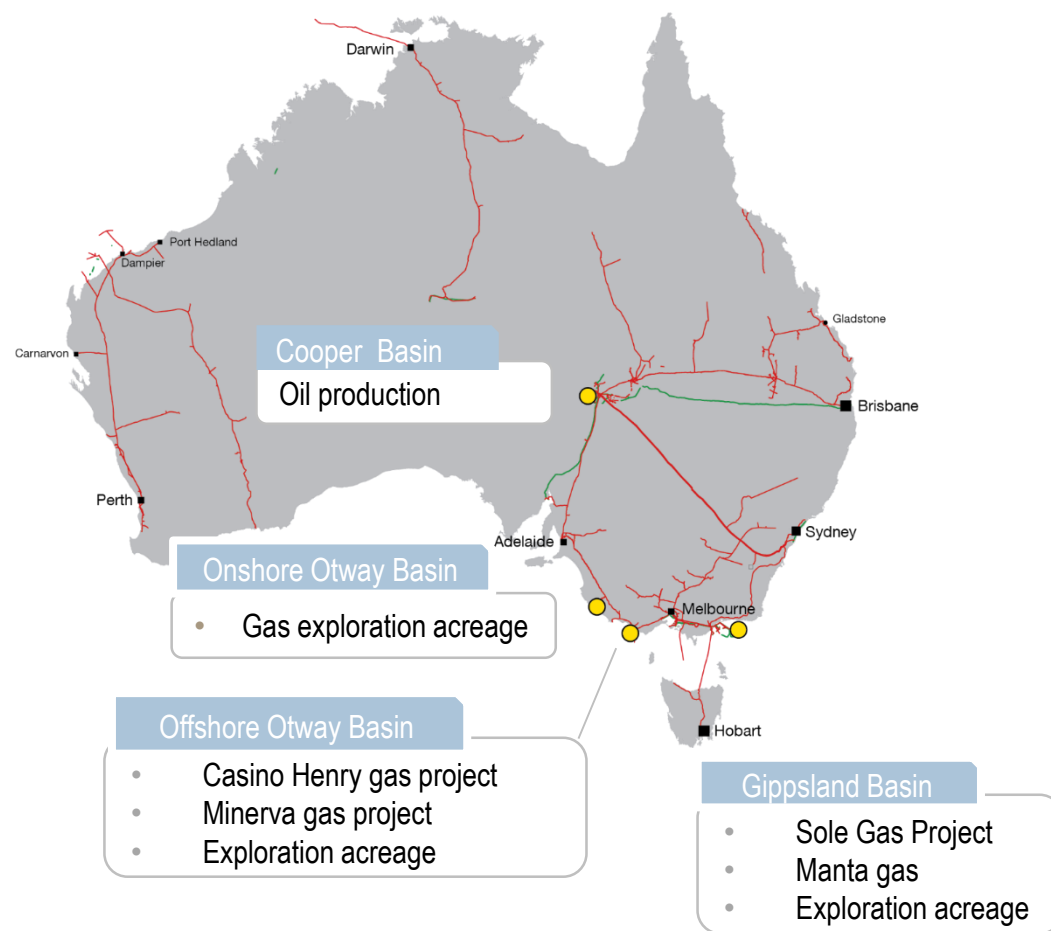
Appendices

Cooper Energy snapshot

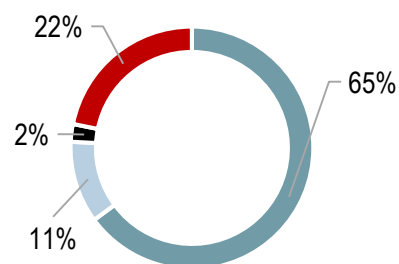
Portfolio built around winning position on cost curve

Key statistics*

Proved & Probable Reserves	52.4 MMboe
Contingent Resources (2C)	34.9 MMboe
Production FY19 guidance	1.4 MMboe
Market capitalisation	\$802 million
Net cash/(debt)	\$7 million
Issued share capital (million)	1,621.6

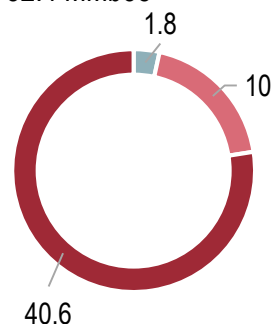


Share register
% of issued share capital



- Domestic institutional
- Foreign institutional
- Directors & employees
- Private

Proved & Probable Reserves
52.4 MMboe



- Cooper Basin oil
- Otway Basin gas and gas liquids
- Gippsland Basin gas

Capital expenditure; updated guidance

Revision to FY19 capex expectations brought by timing of Otway Basin exploration

\$ 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

Previous guidance update to reflect

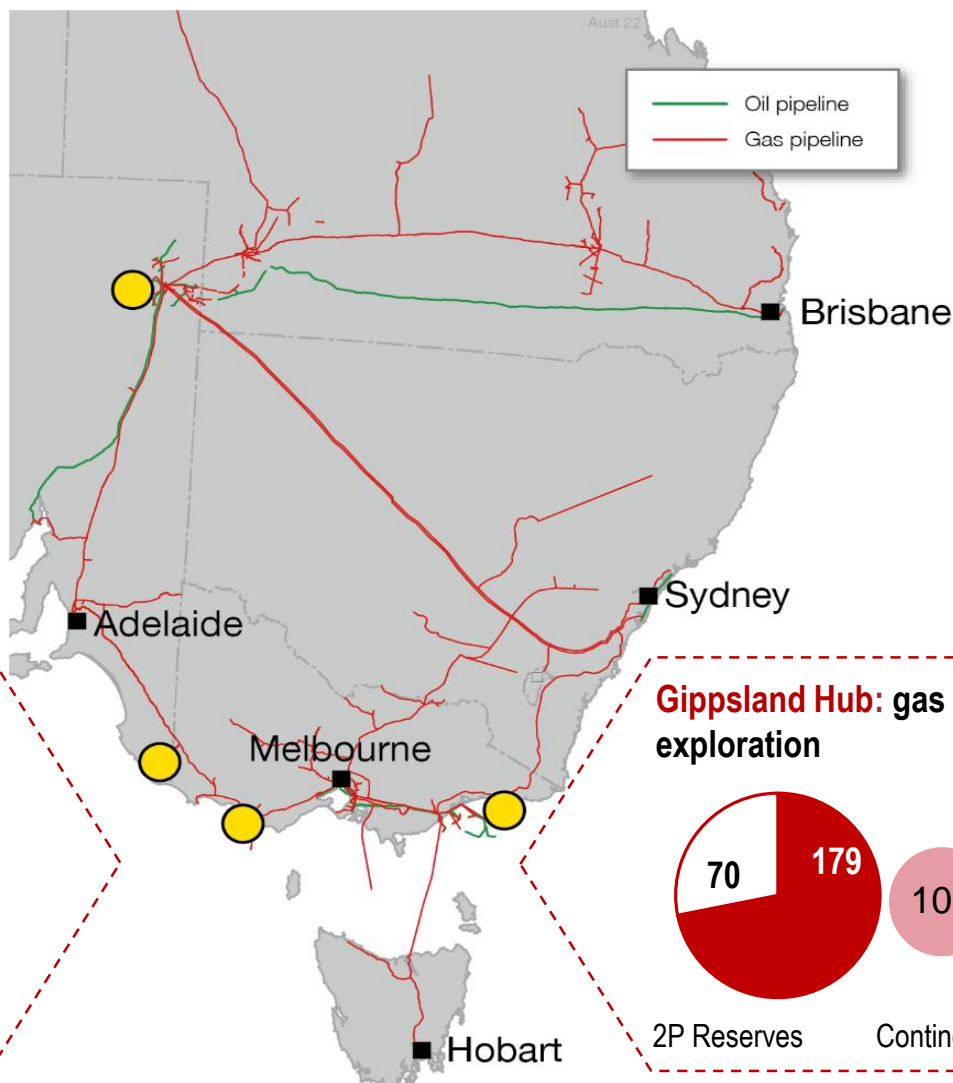
- Inclusion of Offshore Otway exploration in June quarter
- Inclusion of capital expenditure on Sole in FY19 previously expected to occur in FY18 or FY20 (approx. \$19 million)
- Deferral of Henry development well expenditure (\$1.7 million)
- Capitalised interest incurred in FY19 H1 (\$6 million); no capitalised interest for H2 included in guidance

Cooper Energy gas business

Multi-basin gas portfolio built on 2 hubs well located for supply to south-east Australia

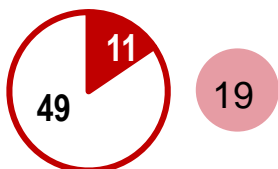


Santos



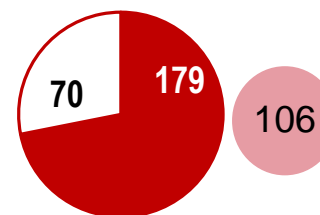
- 2P Reserves contracted
- 2P Reserves uncontracted
- 2C Contingent Resources uncontracted

Otway Basin Hub: gas production, development & exploration



2P Reserves Contingent Resources 2C

Gippsland Hub: gas development & exploration



2P Reserves Contingent Resources 2C



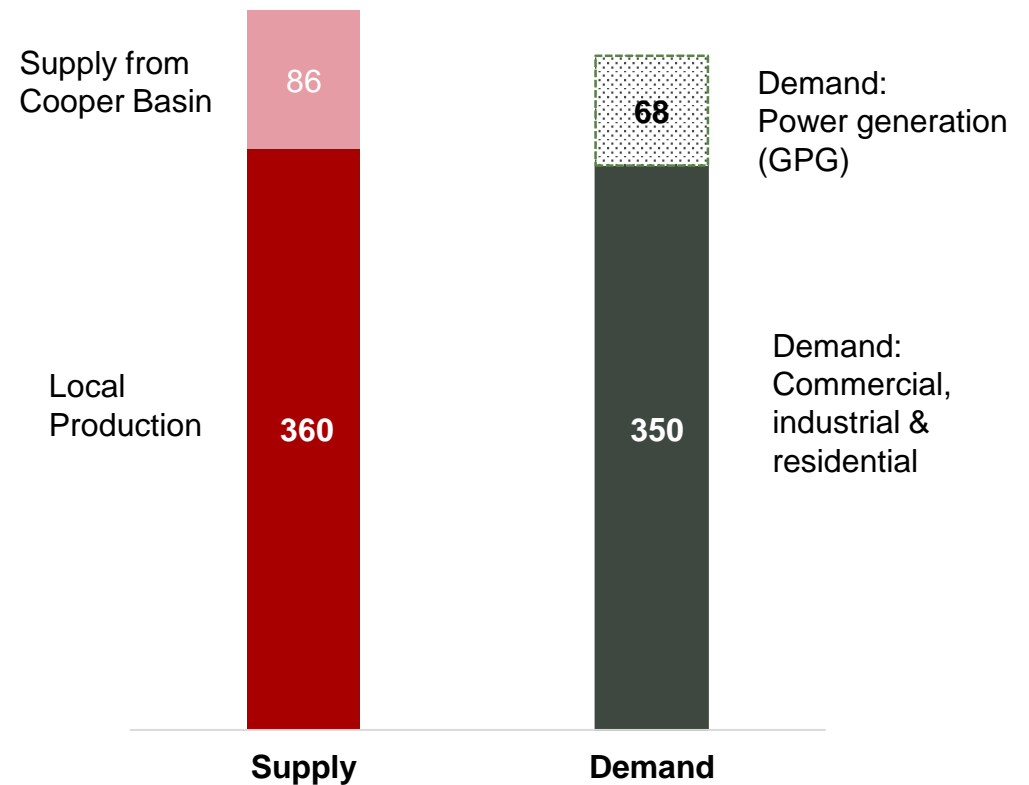
¹ Reserves and Contingent Resources at 30 June 2018 were announced to the ASX on 13 August 2018. The resources information displayed should be read in conjunction with the information provided on the calculation of Reserves and Contingent Resources provided in the appendices to this document. The announcement included recognition of Proved and Probable Reserves for the Sole gas field, the Contingent Resources for which were previously announced 27 February 2017. The Contingent Resources estimate for Manta was announced to the ASX on 16 July 2015.

ACCC Forecast eastern Australia gas supply and demand outlook

Southern production shortfalls anticipated demand, Cooper Basin gas forecast available to meet market

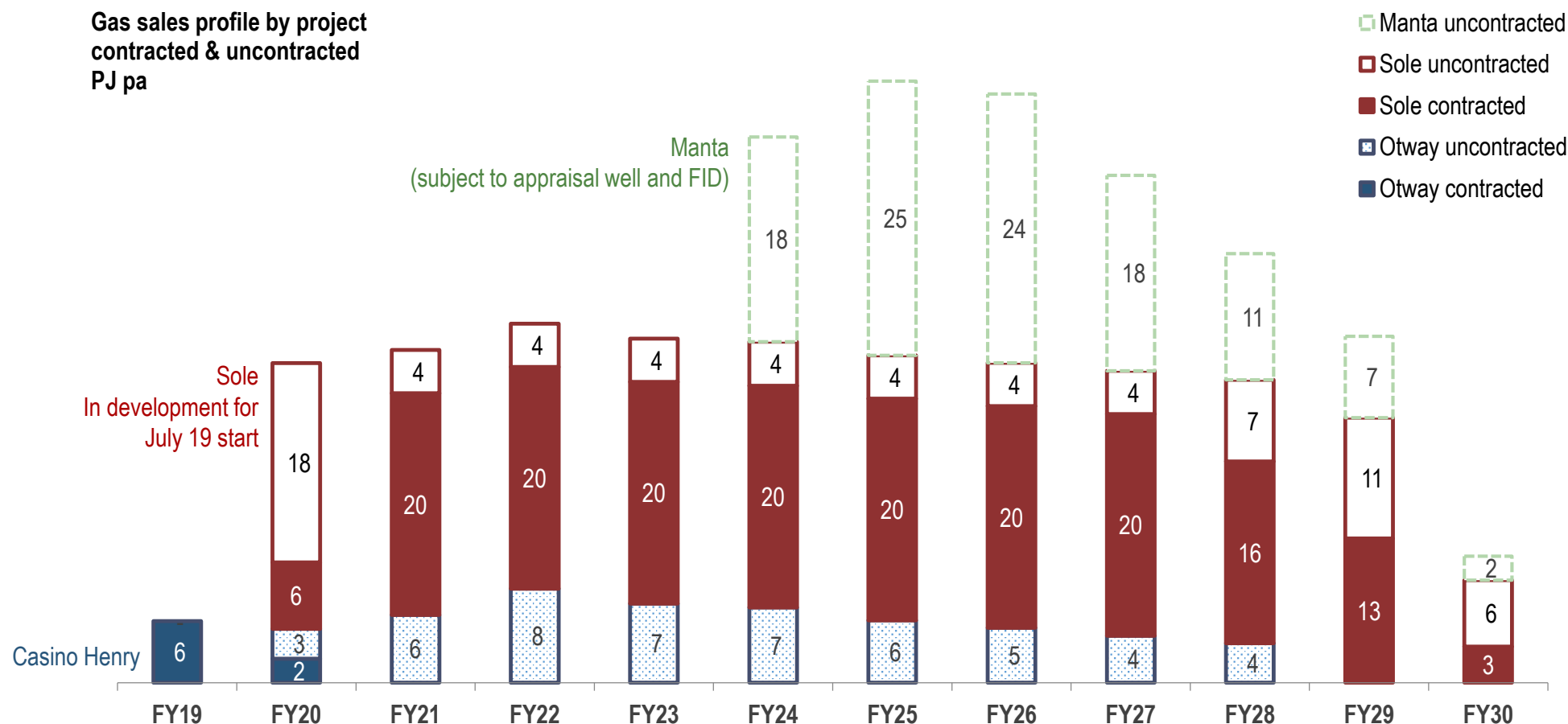
- ACCC forecast “tight” supply for southern states in 2019
- Shortfall of local production over demand inclusive of GPG demand, which can be variable
- Supply anticipated to be available from Cooper Basin, and surplus Qld LNG producers forecast 76 PJ available in excess of domestic and contracted LNG requirements

**ACCC forecast southern states gas supply-demand balance 2019
(including a portion of Cooper Basin supply)
PJ**



Profile of contracted and uncontracted gas by project

Existing reserves and resources offer growth before exploration upside



Assumes:

- Sole sales from July 2019 which is subject to completion and Orbest Gas Plant availability. Sole daily production rate assumed is 68 TJ/day.
- Manta subject to Manta-3 appraisal well expected to drill Dec '20-Feb 21; Manta profile illustrates all Manta gas (106 PJ 2C) as uncontracted (including 4 PJ pa option held by AGL)
- Henry development well required for Casino Henry, expect to drill Dec '20 – 'Feb 21
- No exploration success

Note: all numbers rounded

5 levers for the next wave of growth

Value creation opportunities within existing portfolio to be pursued

Gas contracting



- Contract CY 20-22
- ~ 43 PJ of gas

Infrastructure



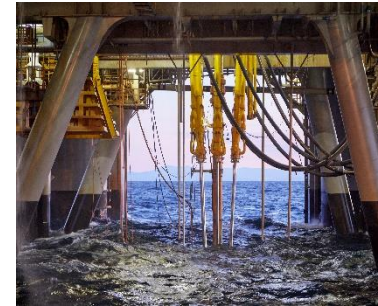
- Minerva Gas Plant
- Acquire & connect

Undeveloped gas



- Develop 285 PJ
- Sole, Casino Henry

Contingent Resources



- 125 PJ
- Manta, Black Watch

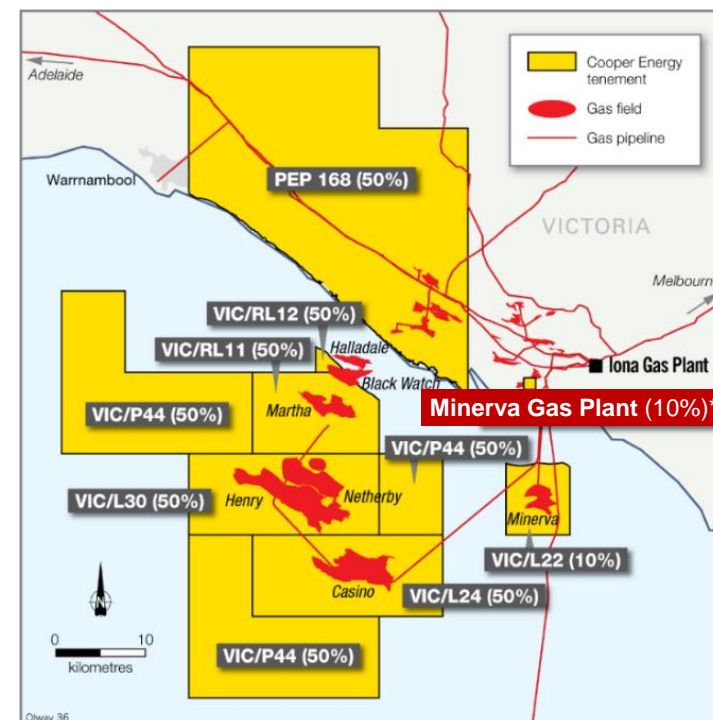
Exploration



- Drill
- 4 exploration targets; Otway & Gippsland

Minerva Gas Plant

Strategically located offering gains in gas price, processing, recovery rates & production



* Equity to increase to 50% on completion of acquisition by Casino Henry Joint Venture as announced 1 May 2018

Minerva Gas Plant acquisition

- Casino Henry Joint Venture agreed acquisition of Minerva Gas Plant from BHP
- 150 TJ/day capacity, plus liquids handling capability
- Transaction subject to cessation of processing gas from Minerva Gas Field, regulatory approvals and assignments
- Minerva Cutback Project: engineering design advanced for connection of Casino Henry to Minerva Gas Plant
 - 250m pipeline connection
 - Control system integration
- Offers reduced processing costs; productivity and developed reserves increase on lower inlet pressure and processing for future developments

Otway Basin, Penola Trough onshore

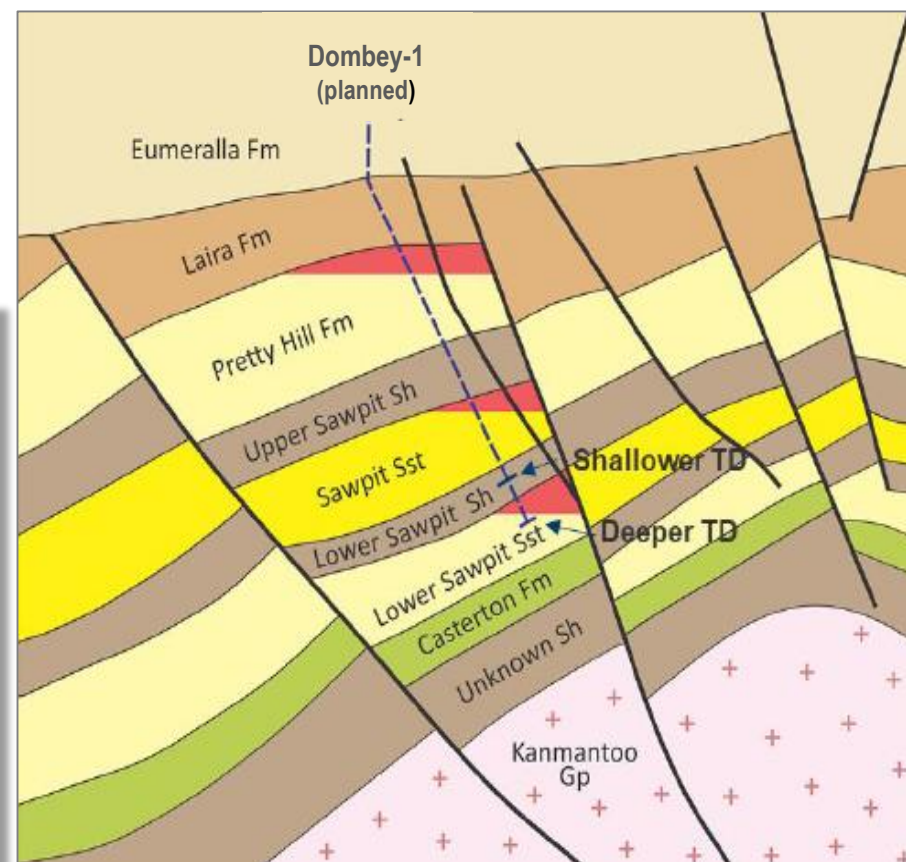
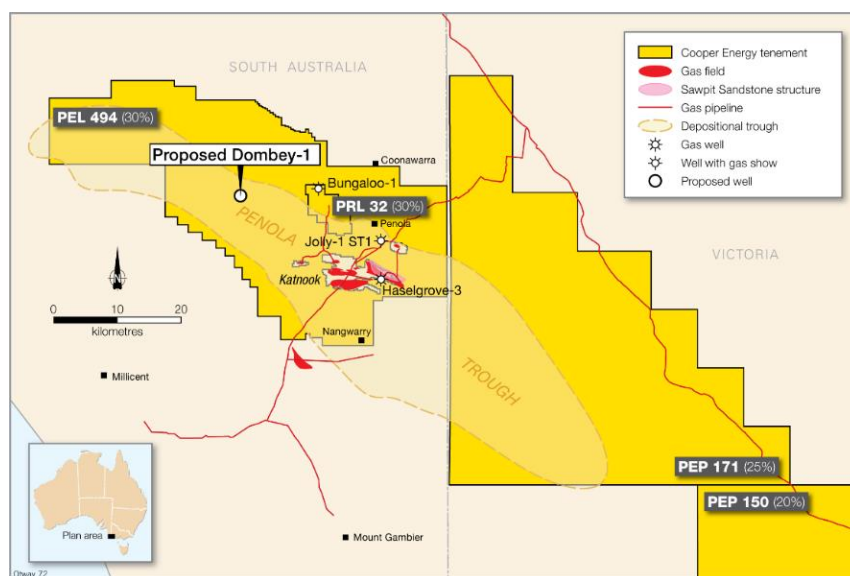
Dombey-1 to be drilled to evaluate Pretty Hill Formation and Sawpit Sandstone potential

South Australia

- Haselgrove-3 discovery in adjoining PPL 62 confirmed conventional gas prospectivity of Sawpit Sandstone at depths below previous producing levels.
- Dombey-1 gas exploration well is testing similar stratigraphic section as Haselgrove gas field. Supported by SA government PACE grant to PEL 494 JV (Cooper Energy 30% interest) of \$6.9 million. Expected from July 2019.

Victoria

- Haselgrove-3 discovery upgraded prospectivity of greater Penola Trough.
- Activities suspended pursuant to moratorium on onshore gas exploration until June 2020.
- A 100% interest in PEP 171 may reduce by up to 50% on fulfilment of farm-in arrangements with Vintage Energy Ltd.



Gippsland Basin

Cost competitive resource, existing plant and Sole production planned for FY19

Sole Gas Project

- FID 29 August 2017
- Sole gas project proceeding to first gas sales mid-2019

Manta

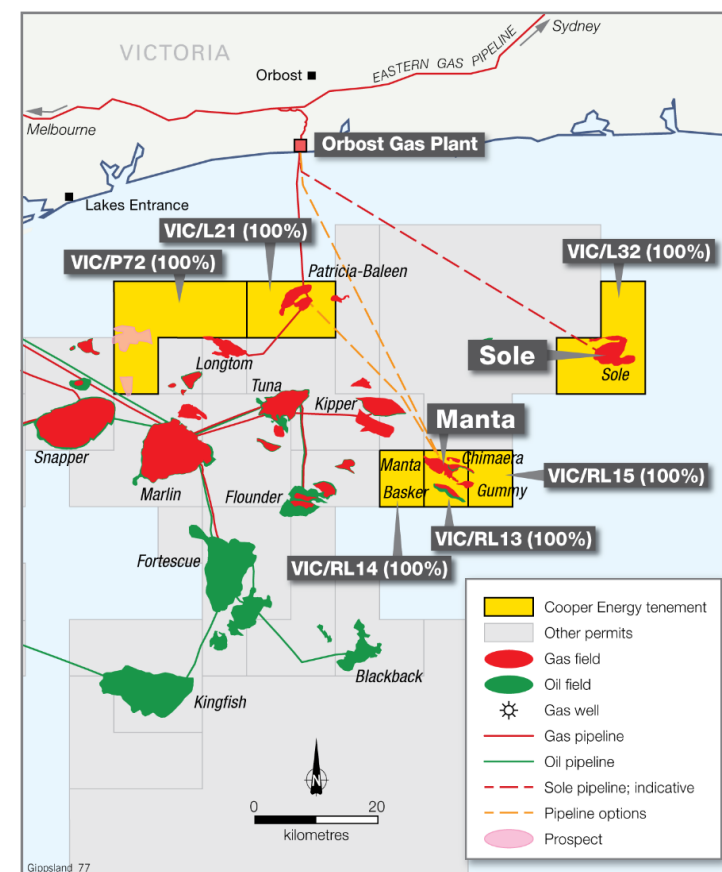
- Secured provision for processing at Orbost Gas Processing Facility under agreement with APA
- Detailed planning to commence
- Economics enhanced by cost discovery from Sole FEED and gas price and demand expectations

Key assets: (all 100% equity & Operator)

- Sole gas project (VIC/L32)
- Manta gas resource (VIC/RL13,14,15)
- Patricia Baleen gas field & associated infrastructure (VIC/L21)
- VIC/P72 exploration permit

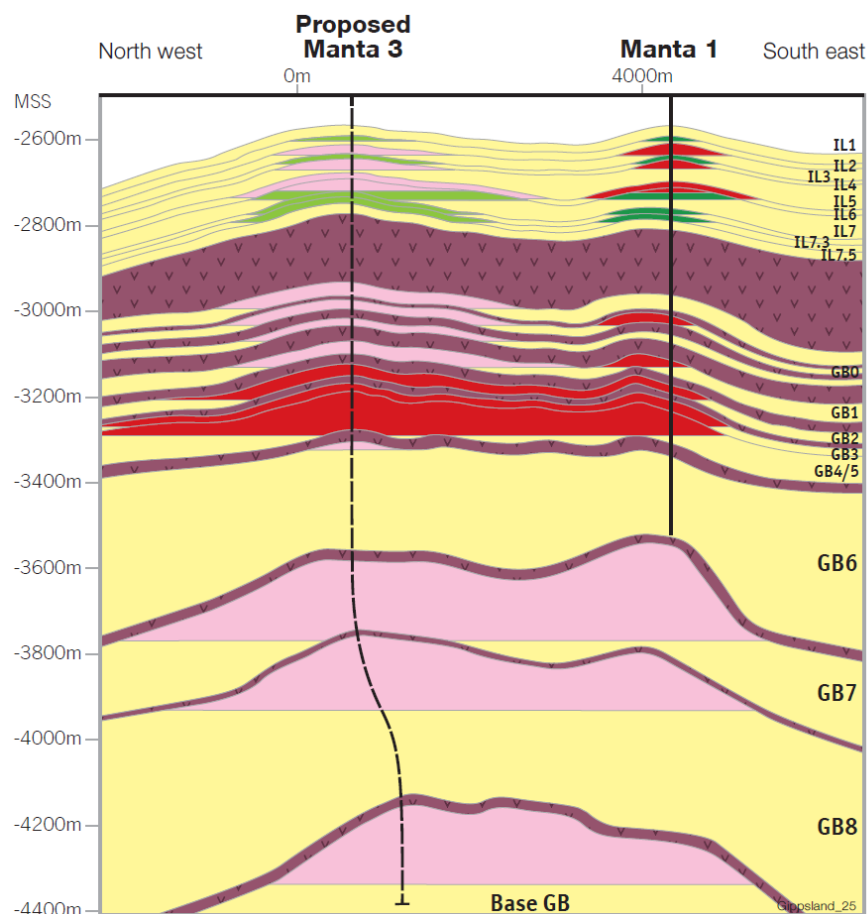
	Sole 2P Reserves ¹	Manta 2C Resource ¹
Sales gas PJ	249	106
Condensate MMbbl	-	2.6

¹ Reserves and Contingent Resources at 25 August 2017 were announced to the ASX on 29 August 2017. The resources information displayed should be read in conjunction with the information provided in the calculation of Reserves and Contingent Resources provided in the appendices to this document. The announcement included recognition of proved and probable reserves for the Sole gas field, the contingent resource for which was previously announced 27 February 2017. The contingent resource estimate for the Manta resource was announced to the ASX on 16 July 2015.



Manta gas and liquids resource

Gas and liquids Contingent Resource with exploration potential



Manta Contingent Resource¹ estimate

		1C	2C	3C
Oil	MMbbl	0.0	0.6	1.2
Condensate	MMbbl	1.7	2.6	4.0
Gas	PJ	68	106	165

Manta unrisks Prospective Resource¹ estimate

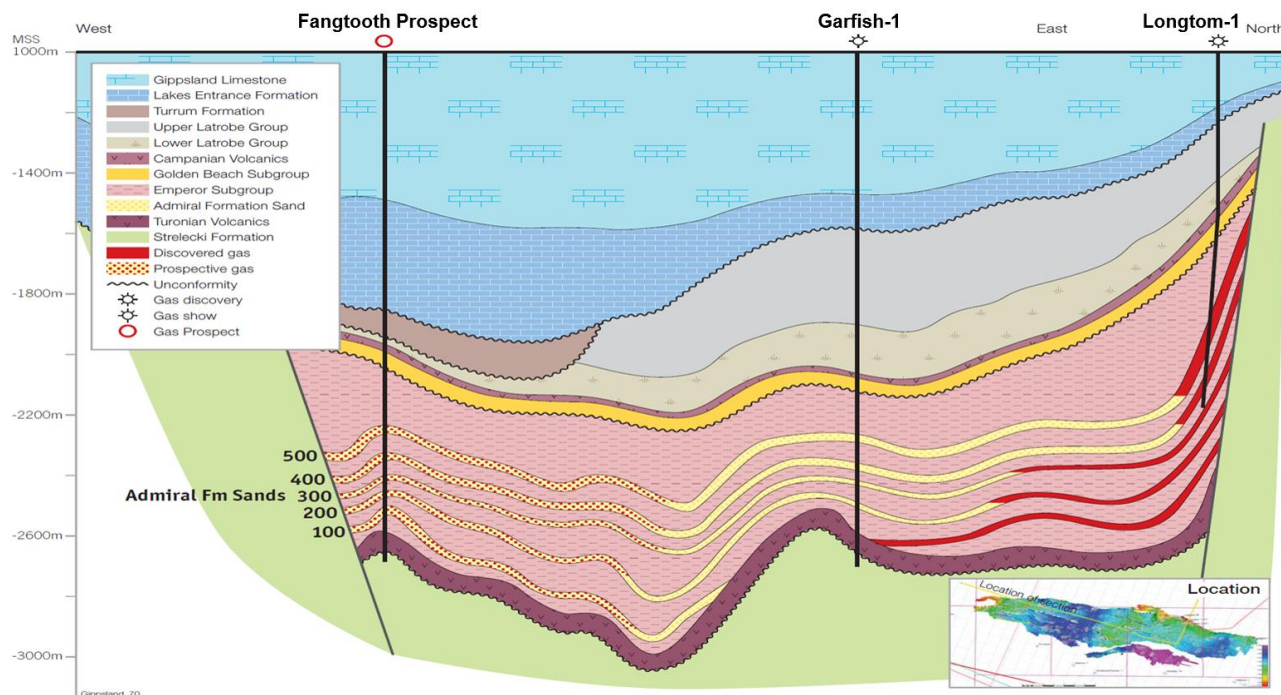
		Low (P90)	Best (P50)	High (P10)
Oil	MMbbl	1.0	1.5	2.3
Condensate	MMbbl	6.8	12.9	25.9
Gas	PJ	275.8	526.2	1,054.2

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.

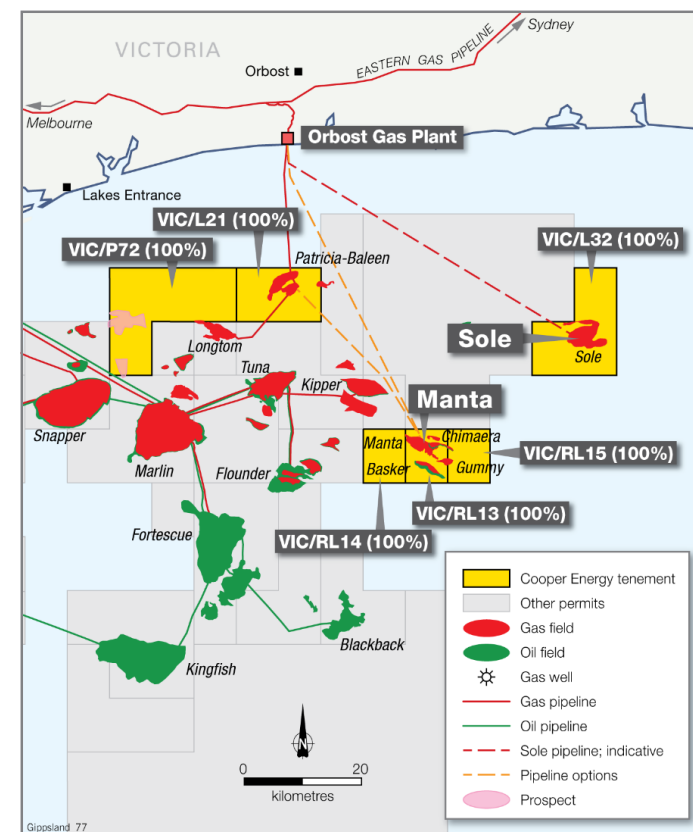
¹ Contingent Resource for the Manta gas and liquids resource was announced to ASX on 16 July 2015. Prospective Resource for the field was announced to the ASX on 4 May 2016. Cooper Energy confirms that it is not aware of any new information or data that materially affects the information included in the announcements of 16 July 2015 of 4 May 2016 and that all the material assumptions and technical parameters underpinning the estimates in the announcements continue to apply and have not materially changed.

Exploration: Gippsland Basin

New prospectivity adjacent to existing Patricia Baleen infrastructure



- VIC/P72 adjoins VIC/L21 (Cooper Energy 100%) which holds the depleted Patricia Baleen gas field and its associated subsea production infrastructure connected to the Orbost Gas Plant
- 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



VIC/P72

Equity: 100%

Term: 6 years

Work program: 3 years guaranteed

- 260 km² 3D seismic reprocessing studies
- 1 well

Reserves and Contingent Resources at 30 June 2018

Reserves	Unit	1P (Proved)				2P (Proved + Probable)				3P (Proved + Probable + Possible)			
		Cooper	Otway	Gippsland	Total ¹	Cooper	Otway	Gippsland	Total ¹	Cooper	Otway	Gippsland	Total ¹
Developed													
Sales Gas	PJ	0	15	0.0	15	0	26	0	26	0	36	0	36
Oil + Cond	MMbbl	1.1	0.0	0.0	1.1	1.4	0.0	0.0	1.1	1.9	0.0	0.0	1.9
Sub-total	MMboe	1.1	2.5	0.0	3.6	1.4	4.3	0.0	5.7	1.9	6.0	0.0	7.8
Undeveloped													
Sales Gas	PJ	0	26	209	235	0	35	249	283	0	57	293	350
Oil + Cond	MMbbl	0.1	0.0	0.0	0.1	0.4	0.0	0.0	0.7	1.4	0.0	0.0	1.4
Sub-total	MMboe	0.1	4.2	34.2	38.5	0.4	5.7	40.6	46.7	1.4	9.3	47.8	58.6
Total ¹	MMboe	1.2	6.7	34.2	42.1	1.8	10.0	40.6	52.4	3.3	15.3	47.8	66.4

¹ Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category. As a result, the 1P estimates may be conservative and the 3P estimates may be optimistic due to the effects of arithmetic summation. The Reserves exclude Cooper Energy's share of future fuel usage. See comment on conversion factor change in 'Notes on calculation of Reserves and Resources'.

Contingent Resources	1C			2C			3C		
	Gas	Oil	Total ¹	Gas	Oil	Total	Gas	Oil	Total
	PJ	MMbbl	MMboe	PJ	MMbbl	MMboe	PJ	MMbbl	MMboe
Gippsland	68	1.7	12.7	106	3.2	20.4	165	5.3	32.0
Otway	12	0.0	2.0	19	0.0	3.1	28	0.0	4.6
Cooper	0	0.1	0.1	0	0.1	0.1	0	0.2	0.2
Total¹	80	1.8	14.8	125	3.4	23.6	193	5.5	36.8

¹ Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category. As a result, the 1C estimate may be conservative and the 3C estimate may be optimistic due to the effects of arithmetic summation. See comment on conversion factor change in 'Notes on calculation of Reserves and Resources'.

Notes on calculation of Reserves and Resources

Notes on calculation of Reserves and Contingent Resources

Cooper Energy has completed its own estimation of Reserves and Contingent Resources for its fully-operated Gippsland Basin assets, and elsewhere based on information provided by the permit Operators (Beach Energy Ltd for PEL 92, Senex Ltd for Worrior Field, and BHP Billiton Petroleum (Vic) P/L for Minerva Field — in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

All Reserves and Contingent Resources figures in this document are net to Cooper Energy.

Petroleum Reserves and Contingent Resources are prepared using 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 and 1C estimates may be conservative, and aggregated 3P and 3C estimates may be optimistic due to the effects of arithmetic summation. Totals may not exactly reflect arithmetic addition due to rounding.

The Company has changed the FY18 energy conversion factor consistent with Society of Petroleum Engineers (SPE) conversions and PRMS guidance. The previous conversion factor of 1 PJ = 0.172 MMboe was adopted when the Company was predominantly a Cooper Basin oil producer. With the change to a predominantly offshore gas-producing Company, a conversion factor of 1 PJ = 0.163 MMboe (5.8 MMBtu/bbl) is more consistent with industry and SPE standard energy conversions. The new conversion factor has no impact on gas reserves expressed in PJ.

The information contained in this report regarding the Cooper Energy Reserves and Contingent Resources is based on, and fairly represents, information and supporting documentation reviewed by Mr Andrew Thomas who is a full-time employee of Cooper Energy Limited holding the position of General Manager Exploration & Subsurface, holds a Bachelor of Science (Hons), is a member of the American Association of Petroleum Geologists and 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.

Reserves

Under the SPE PRMS 2018, “Reserves are those quantities of petroleum 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 comprises Sole Field only, where the Contingent Resources assessment at 30 June 2017 as announced to the ASX on 29 August 2017 has been reclassified to Reserves.

Contingent Resources

Under the SPE PRMS 2018, “Contingent Resources are “those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies”.

The Contingent Resources assessment includes resources in the Gippsland, Otway and Cooper basins. The following material Contingent Resources assessment was released to the ASX:

- Manta Field on 16 July 2015

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

Basker Field Contingent Resources reported on 18 August 2014 and carried unchanged through FY17 have been reclassified as Discovered Unrecoverable in FY18 due to approval of field abandonment.

Senior management

Managing Director David Maxwell

David Maxwell has over 30 years' experience as a senior executive with companies such as BG Group, Woodside and Santos. As Senior Vice President at QGC, a BG Group business, he led BG's entry into Australia, its alliance with and subsequent takeover of QGC. Roles at Woodside included director of gas and marketing and membership of Woodside's executive committee.

General Manager, Development Duncan Clegg

Duncan Clegg has over 35 years' experience in upstream and midstream oil and gas development, including management positions at Shell and Woodside, leading oil and gas developments including FPSO, subsea and fixed platforms developments. At Woodside Duncan held several senior executive positions including Director of the Australian Business Unit, Director of the African Business Unit and CEO of the North West Shelf Venture.

Company Secretary & Legal Counsel Alison Evans

Alison Evans is an experienced company secretary and corporate legal counsel with extensive knowledge of corporate and commercial law in the resources and energy sectors. Alison has held Company Secretary and Legal Counsel roles at a number of minerals and energy companies including Centrex Metals, GTL Energy and AGL. Ms Evans' public company experience is supported by work at leading corporate law firms.

General Manager, Commercial & Business Development Eddy Glavas

Eddy Glavas has more than 20 years' experience in business development, finance, commercial, portfolio management and strategy, including 16 years in oil & gas. Prior to joining Cooper Energy, he was employed by Santos as Manager Corporate Development with responsibility for managing multi-disciplinary teams tasked with mergers, acquisitions, partnerships and divestitures.

General Manager, Projects Michael Jacobsen

Michael Jacobsen has over 25 years' experience in upstream oil and gas specialising in major capital works projects and field developments. He has worked more than 10 years with engineering and construction contractors and then progressed to managing multi discipline teams on major capital projects for E&P companies.

General Manager, Operations Iain MacDougall

Iain MacDougall has more than 30 years experience in the upstream petroleum exploration and production sector. His experience includes senior management positions with independent operators and wide ranging international experience with Schlumberger. In Australia, Iain's previous roles include Production and Engineering Manager and then acting CEO at Stuart Petroleum prior to the takeover by Senex Energy.

Chief Financial Officer Virginia Suttell

Virginia Suttell is a chartered accountant with more than 20 years' experience, including 16 years in publicly listed entities, principally in group finance and secretarial roles in the resources and media sectors. This has included the role of Chief Financial Officer and Company Secretary for Monax Mining Limited and Marmota Energy Limited. Other previous appointments include Group Financial Controller at Austereo Group Limited.

General Manager, Exploration & Subsurface Andrew Thomas

Andrew Thomas is a successful geoscientist with over 30 years' experience in oil and gas exploration and development in companies including Geoscience Australia, Santos, Gulf Canada and Newfield Exploration. Prior to joining Cooper Energy he was SE Asia New Ventures Manager and Exploration Manager for offshore Sarawak for Newfield Exploration.

Senior Management Team



Company Secretary &
Legal Counsel
Alison Evans

General Manager,
Operations Iain
MacDougall

General Manager,
Development
Duncan Clegg

General Manager,
Commercial & Business
Development
Eddy Glavas

General Manager,
Projects
Michael Jacobsen

General Manager,
Exploration &
Subsurface
Andrew Thomas

Managing Director
David Maxwell

Chief Financial Officer
Virginia Suttell

Abbreviations

\$, A\$	Australian dollars unless specified otherwise
Bbl	barrels of oil
Boe	barrel of oil equivalent
EBITDA	earnings before interest, tax, depreciation and amortisation
FEED	Front end engineering and design
kbbbl	thousand barrels
m	metres
MMbbl	million barrels of oil
MMboe	million barrels of oil equivalent
NPAT	net profit after tax
PEL 92	Joint Venture conducting operations in Western Flank Cooper Basin Petroleum Retention Licences 85–104 previously encompassed by the PEL 92 exploration licence
PEL 93	Joint Venture conducting operations in Cooper Basin Petroleum Retention Licences PRL 231-233 and PRL 237 previously encompassed by the PEL 93 exploration licence
TRCFR	Total Recordable Case Frequency Rate. Recordable cases per million hours worked
1P Reserves	Proved Reserves
2P Reserves	Proved and Probable Reserves
3P Reserves	Proved, Probable and Possible Reserves
1C, 2C, 3C	high, medium and low estimates of Contingent Resources