29 August 2023

FY23 full year results and FY24 outlook

COOPER ENERGY

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The following are non-IFRS measures: EBITDAX (earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment); EBITDA (earnings before interest, tax, depreciation, depletion and impairment); EBIT (earnings before interest and tax); underlying profit; and free cash flow (operating cash flows less investing cash flows net of acquisitions and disposals and major growth capex less lease liability payments). Cooper Energy presents these measures to provide an understanding of Cooper Energy's performance. They are not audited but are from financial statements reviewed by Cooper Energy's auditor. Underlying profit excludes the impacts of asset acquisitions and disposals, impairments, hedging, and items that fluctuate between periods.

Numbers in this report have been rounded. As a result, some figures may differ insignificantly due to rounding and totals reported may differ insignificantly from arithmetic addition of the rounded numbers.

Approved and authorised for release by Jane Norman, Managing Director and CEO, Cooper Energy Limited, Level 8, 70 Franklin Street, Adelaide 5000.

Footnotes are located at the end of the presentation on slides 36-37.

Key Contacts

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Year in review

Record FY23 production and u-EBITDAX

Underpinned by strong safety and environmental performance

Safety and environment	Lost time incidents **0** cases	TRIFR[1] **4.38** (industry 5.68)	Net organisational emissions[2] **0** tonnes (FY23)
Production and financial	Production **3.56** MMboe +7.8%	Operating cashflow **$62.8** million +8.7%	u-EBITDAX **$109.3** million +35.4%
People and operations	**Team refreshed & new structure in place**	**OGPP Operatorship from 22 May**	**Exempt from $12/GJ price cap under the Gas Code**

1. Organisational carbon emissions voluntarily fully offset for FY23. These consist of Scope-1 (direct), Scope-2 (purchased electricity) and relevant Scope-3 emissions (embedded energy and business travel). Downstream Customer Scope-3 transportation and combustion emissions are not included.

Health, safety, environment and community

Results ahead of industry benchmarks through disciplined operations

Safety

- Zero lost time injuries
- One medical treatment injury
  - Ahead of industry benchmark TRIFR[1]

Environment

- Two minor emissions exceedance events at Athena Gas Plant

Community

- Proactive engagement with stakeholders in the areas where we operate

Safety metrics	FY22	FY23
Hours worked	220,238	**228,483**
Recordable injuries	0	**1**
Lost time injuries (LTI)	0	**0**
LTI frequency rate[2]	0.0	**0.0**
Total recordable injury frequency rate (TRIFR)	0.00	**4.38**
Industry TRIFR[3]	6.91	**5.68**

Organisational changes
Refreshed executive team

Jane Norman

Managing Director & Chief Executive Officer

Chad Wilson

Chief Operating Officer

Effective 23 October 2023

Dan Young

Chief Financial Officer

Andrew Thomas

Chief Exploration & Subsurface Officer

Eddy Glavas

Chief Commercial Officer

Nathan Childs

Chief Corporate Services Officer

Effective 1 November 2023

Ying Luo

Chief Advisor & GM Strategy

Nicole Ortigosa

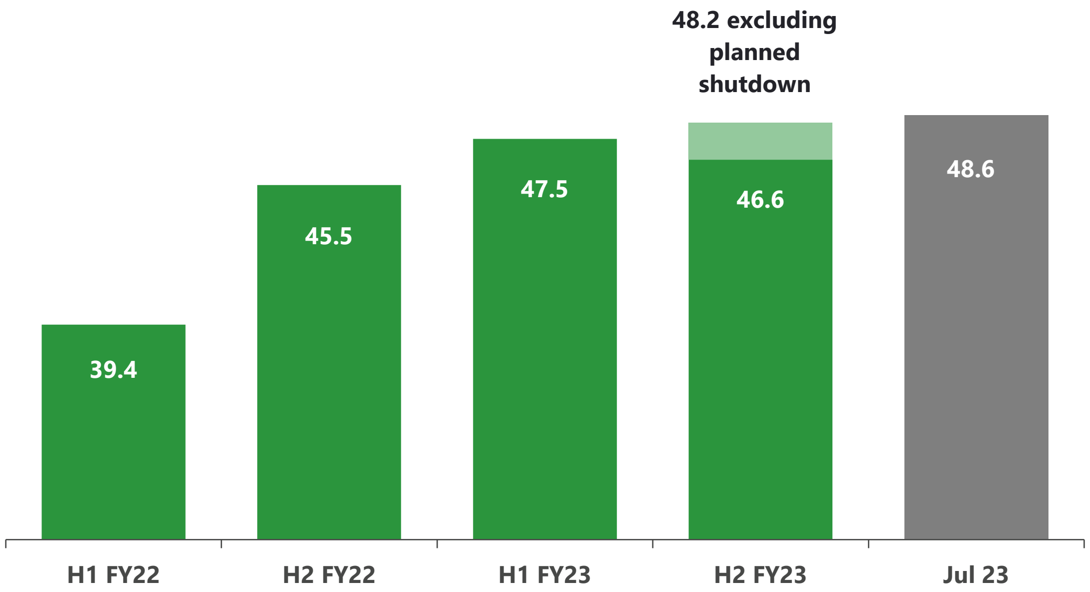
Company Secretary & General Counsel

Orbost gas processing plant

Improving stability following transfer of operatorship

- FY23 average processing rate 47.1 TJ/d[1] (FY22 42.5 TJ/d)
  - Contracted average annual daily volume of ~43.8 TJ/d
- Plant stability improved with increased Cooper Energy presence
  - Transfer of operatorship 22 May 2023
- Performance improvement plan underway
  - Focused on reducing sulphur fouling and reducing time taken for absorber bed cleans
    - Absorber bed clean times reduced from 48 hours to less than 30 hours since May 2023
- Organisational changes and Melbourne based engineering resources to support performance improvement plan

OGPP average processing rate, TJ/d



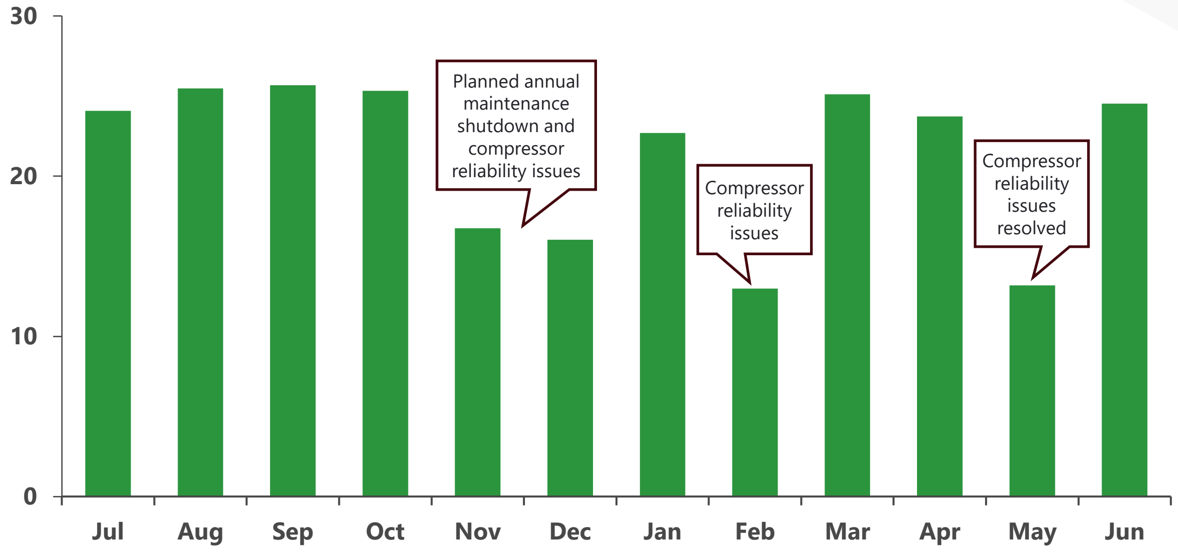
Performance improvement plan underway to increase uptime and average processing rate

Athena gas plant

Longstanding compressor reliability issue resolved in May 2023

- FY23 average processing rate 21.4 TJ/d (100% gross)
  - FY22 average processing rate 23.6 TJ/d[1] (100% gross)
- Casino, Henry and Netherby wells cycled to optimise performance
- Rates impacted by unplanned downtime of export compressor
  - May 2023 remediation successfully solved long standing reliability issue
- Casino, Henry and Netherby 2P developed reserves support production to 2028 and beyond

Athena average processing rate, TJ/d (100% gross)



Increased plant reliability to underpin stable FY24 production

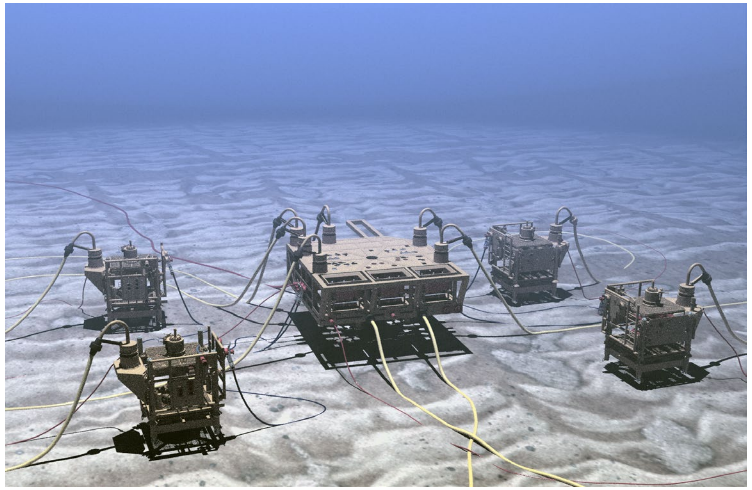
Non-operated production and other activities

Focus on safe completion of BMG decommissioning on-time & company-wide cost reductions

Cooper Basin oil

- Divestment of non-core assets to Bass Oil in August 2022 for A$0.65mm
- Retained 25% interest in PEL 92, Western Flank (Beach Energy 75% and operator)
- FY23 production ~319 bbls/d, net to COE's 25% interest (FY22: 335 bbls/d)

BMG wells decommissioning



- FY23 activity, A$27.9mm (100% gross basis)
  - Detailed planning and long leads
  - Contracts awarded to support services
  - Assurance reviews
  - Pre-abandonment programme

Cost reductions

- Restructure to ensure organisation is 'future fit'
- Engineering support for OGPP & AGP centralised in Melbourne, proximal to both operational sites
- FY24 targeting minimum 10% reduction to G&A

Government policy support for domestic gas producers

Encouraging mid cap operators focussed on domestic supply

	Key details
Mandatory Gas Code regulations	▪ Carve out for domestic suppliers with production of <100 PJ/y — Cooper Energy eligible for exemption from A$12/GJ price cap — Ministerial exemption expected to be granted to larger producers for domestic GSAs to ensure JV alignment ▪ Foundation GSAs commercialising undeveloped gas are exempt from the code's EOI and other timing provisions
PRRT changes	▪ No impact from new cap on deductible expenditure to 90% of PRRT assessable receipts — Only applies to LNG projects ▪ Clear distinction for conventional domestic gas companies such as Cooper Energy versus large cap LNG exporters

FY23 highlights

Focus on operational excellence to maximise production and cashflow

FY23 Performance

- ✓ Record annual production: ↑ 7.8% to 3.56 MMboe
- ✓ Record annual u-EBITDAX: ↑ 35.4% to $109.3mm
- ✓ Record annual operating cash flow: ↑ 9% to $62.8mm

Focus on operational excellence

- ✓ Executive team refreshed & new organisational structure in place
- ✓ Operations Taskforce established to drive focus on operational excellence across both gas plants
- ✓ Corporate wide cost reduction initiative

Orbost integration

- ✓ Operatorship of OGPP from 22 May, following major hazard facility licence transfer
- ✓ Performance improvement project underway to reduce absorber bed fouling and cleaning time
- ✓ Absorber bed clean times reduced from 48 hours to less than 30 hours

Delivery of BMG

- ✓ BMG de-risked with contracts finalised and pre-abandonment scope completed
- ✓ Plan to complete the well abandonment activities by 31 December 2023

Otway Basin Growth

- ✓ Foundation OP3D gas contract agreed with AGL
- ✓ Exempt from $12/GJ price cap under the Gas Code
- ✓ Positioned to move forward with Otway growth with Transocean rig participation

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Financial highlights

Record production & financial metrics

Step change in operating cashflow, continued deleveraging

$mm unless indicated	FY22	**FY23**	Change
Production, TJe/d[1]	55.5	**59.7**	▲ 8%
Sales revenue	205.4	**196.9**	▼ 4%
Average realised gas price ($/GJ)	8.29	**8.59**	▲ 4%
Production expenses	80.4	**61.1**	▼ 24%
u-EBITDAX	80.7	**109.3**	▲ 35%
Underlying profit/(loss) after tax	14.4	**(5.6)**	▼ 139%
Operating cash flow	57.8	**62.8**	▲ 9%
Capital expenditure	19.5	**42.0**	▲ 115%
	30 Jun 22	**30 Jun 23**	Change
Cash and cash equivalents	247.0[2]	**77.1**	▼ 69%
Drawn debt	158.0	**158.0**	-
(Net debt)/cash	89.0	**(80.9)**	N/M

- Production ↑ 8% due to improved OGPP performance
- Revenue ↓ 4% due to lower sales volumes
  - Third-party gas volumes ↓ to 333 TJ (FY22: 3,185 TJ)
- Production expenses ↓ 24% to $2.80/GJe (FY22: $3.97/GJe)
  - Ownership of OGPP
- u-EBITDAX ↑ due to higher production and margin expansion
- Improved operating cashflow
  - Includes impact of BMG restoration costs, Orbost transition costs and APA July toll
- Underlying loss after tax impacted by higher unit depreciation costs
  - Estimate of restoration costs reset in FY22
  - Acquisition of OGPP

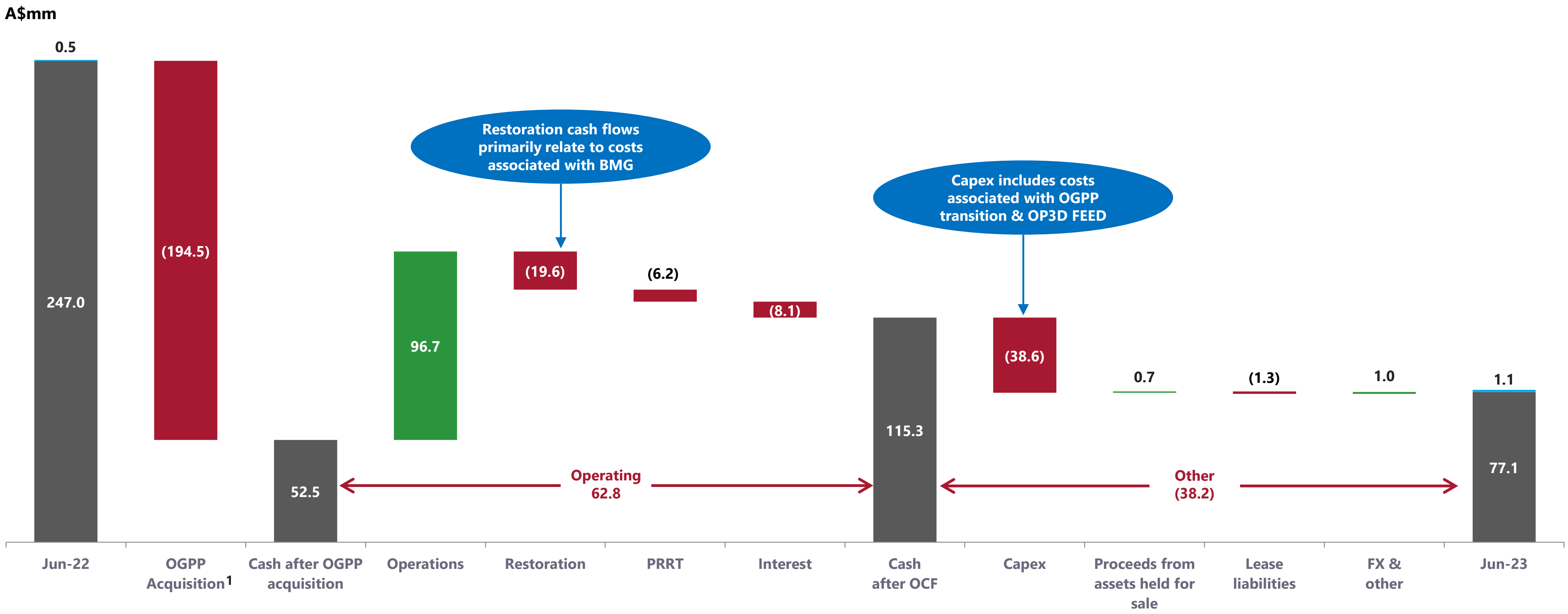
Record u-EBITDAX

u-EBITDAX—bridge from FY22

- FY23 record u-EBITDAX
- Lower sales volumes offset by fewer gas purchases and higher realised prices
- Lower tolling costs as a result of OGPP acquisition offset by higher production costs

Group cash—bridge from June 2022 to June 2023

Cash flow generation impacted by BMG restoration and capex



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Growth, FY24 guidance & wrap-up

Focus on delivering business priorities

Positioning for the next phase of growth in FY24

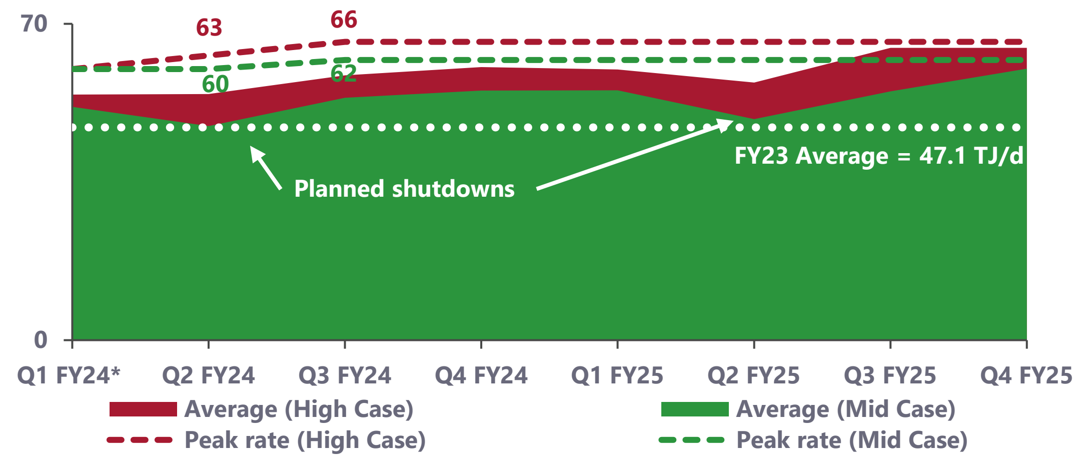
	Q1 FY24	Q2 FY24	Q3 FY24	Q4 FY24
Orbost performance	Orbost performance improvement plan		Mid case avg: mid 50's TJ/d High case avg: high 50's TJ/d	
BMG abandonment		BMG wells abandonment		
Cost savings	Cost savings, including targeting G&A >10%			
Gas sales agreements			Re-contracting existing gas sales agreements begins	
Otway / OP3D	Otway partner alignment			
			Accelerate growth plans including OP3D to FID	

Orbost performance improvement plan

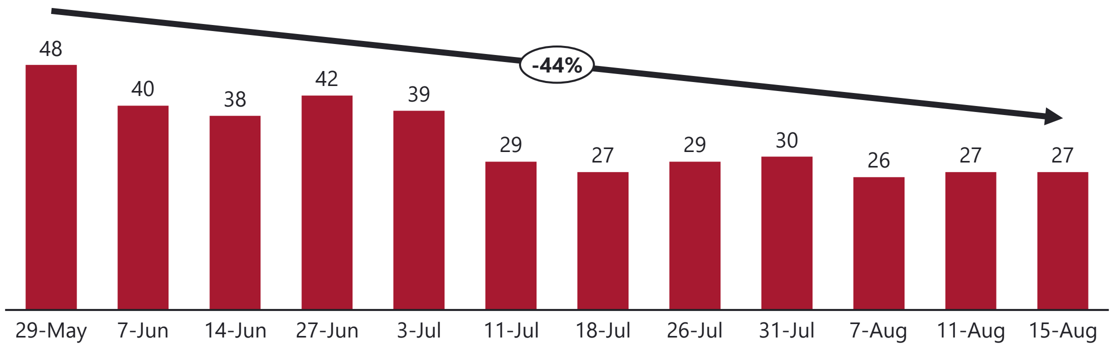
Incremental improvements from identified workstreams

- Operations excellence
  - Improve underlying reliability performance
  - Reduce absorber clean duration
  - Shutdown duration and commissioning
- Implement engineering solutions
  - Six workstreams addressing absorber bed fouling and plant reliability
  - Assessing merits of third absorber option
    - Potentially online in calendar 2025

Orbost production potential, TJ/d



Orbost absorber clean times, hours



Basker Manta Gummy wells abandonment in Q2 FY24

Gippsland Basin subsea decommissioning on track

BMG

- Helix nomination of Q7000 arrival window: 1 – 30 Sep
  - Subject to completing Tui decommissioning and Chevron option to take Q7000 for Gorgon
- Decommissioning seven wells
  - Plug the BMG wells by 31 December 2023
  - Remove remaining subsea flowlines & umbilicals by 31 December 2026
- Latest mid case cost estimate for wells abandonment activities: ~$193 – 198mm on a 100% gross basis
  - Includes contingency for waiting on weather, nonperforming time and an additional general contingency
- Continue to pursue Pertamina for its 10% share

Other near term decommissioning activity

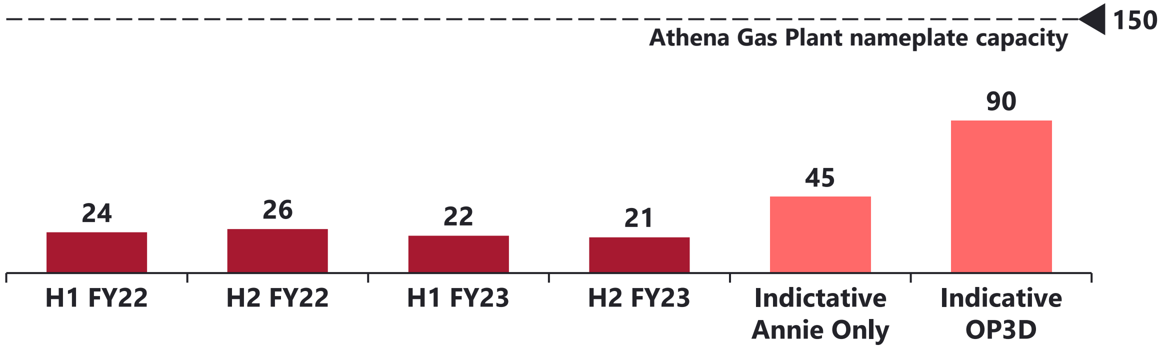
	Within next 5 years
Cooper Basin (PEL92)	25% participating interest; limited spend (<$1mm) in a portion of onshore wells across licence in 2024/25
Minerva (VIC/L22)	10% participating interest in 4 well offshore abandonment project in Otway in 2025/26
BMG (VIC/RL13)	90% participating interest in subsea (umbilicals & flowlines) abandonment project in 2026
Onshore Otway (PRL32)	30% participating interest in 3 well onshore abandonment activity in Otway in 2026/27

Progressing new gas supply to the short domestic market

Clear pathway to commercialisation via Athena Gas Plant

- Immediate priority focus
  - Completion of BMG wells decommissioning & OGPP performance improvement initiatives
- OP3D growth project
  - AGL gas sales agreement underpins investment
  - Rig contract signed
- Resolution of Otway partner alignment

Athena, average processing rate (100% gross), TJ/d

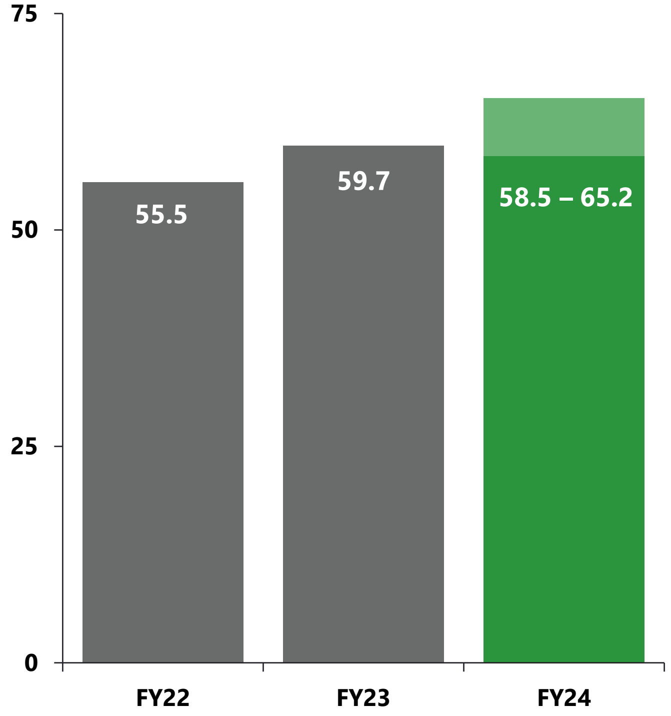


Athena Gas Plant

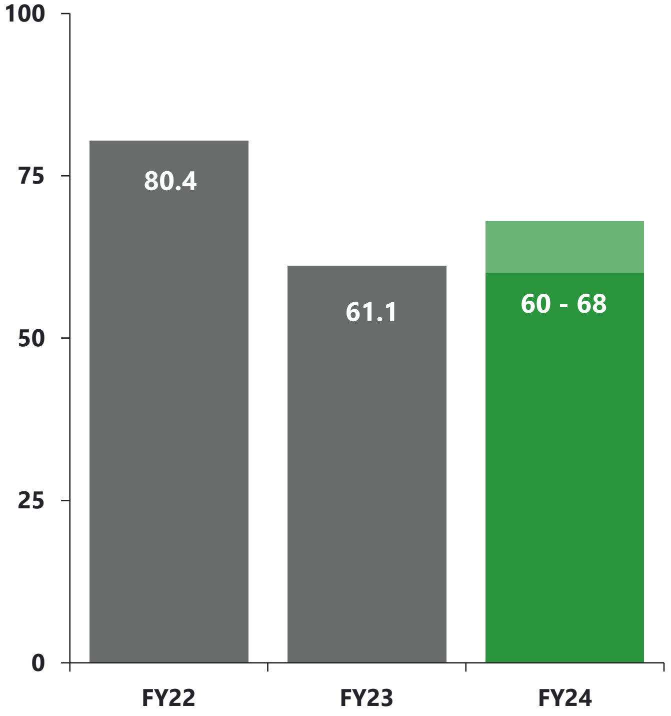
FY24 guidance: production, production expenses & capex

Focus on higher gas production, completing BMG wells abandonment and driving cost efficiencies

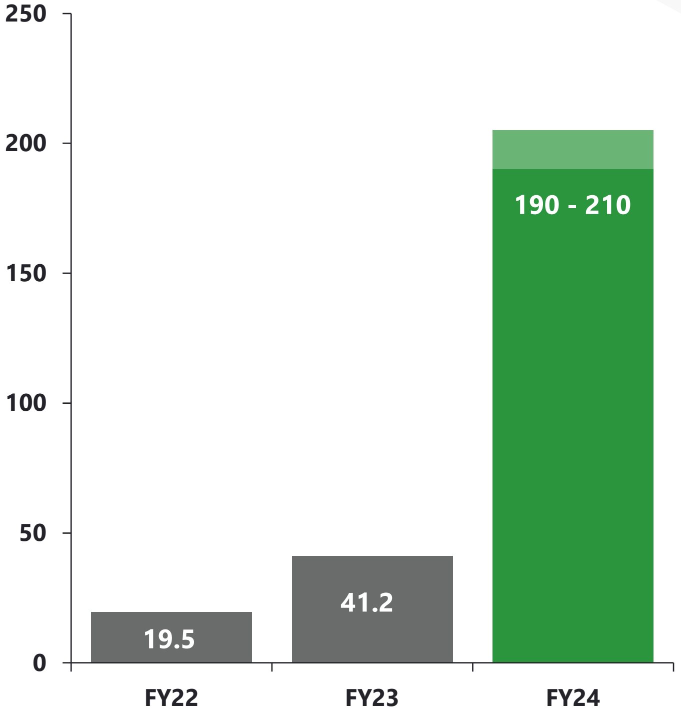
Production: 58.5 – 65.2 TJe/day[1]



FY24 production expenses: $60—68mm[2]



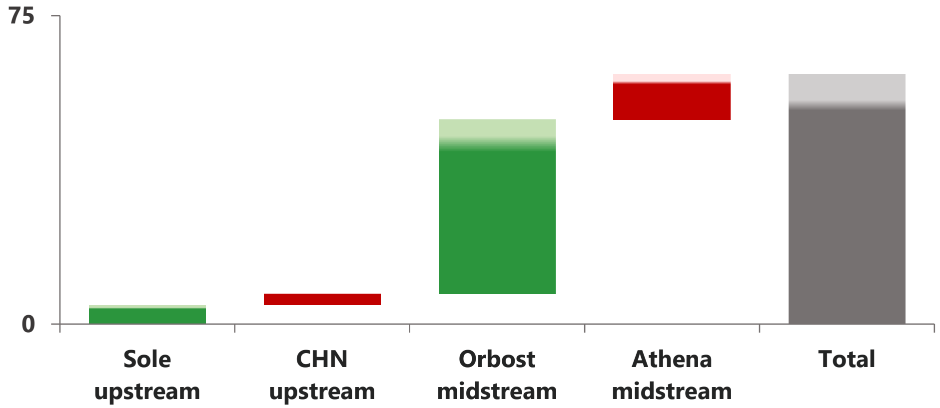
FY24 capex: $190—210mm[3]



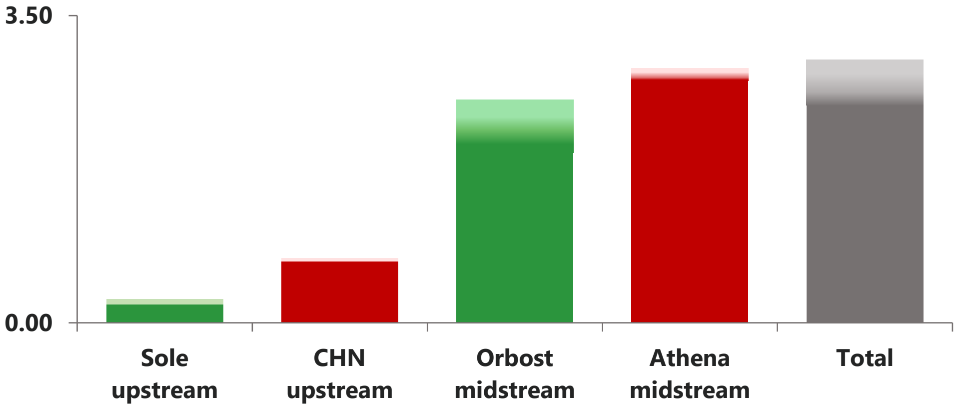
Outlook for production expenses[1]

Expectations for FY24 and beyond

FY24 production expenses, A$mm



FY24 production expenses, A$/GJ



Key drivers for changes to production expenses

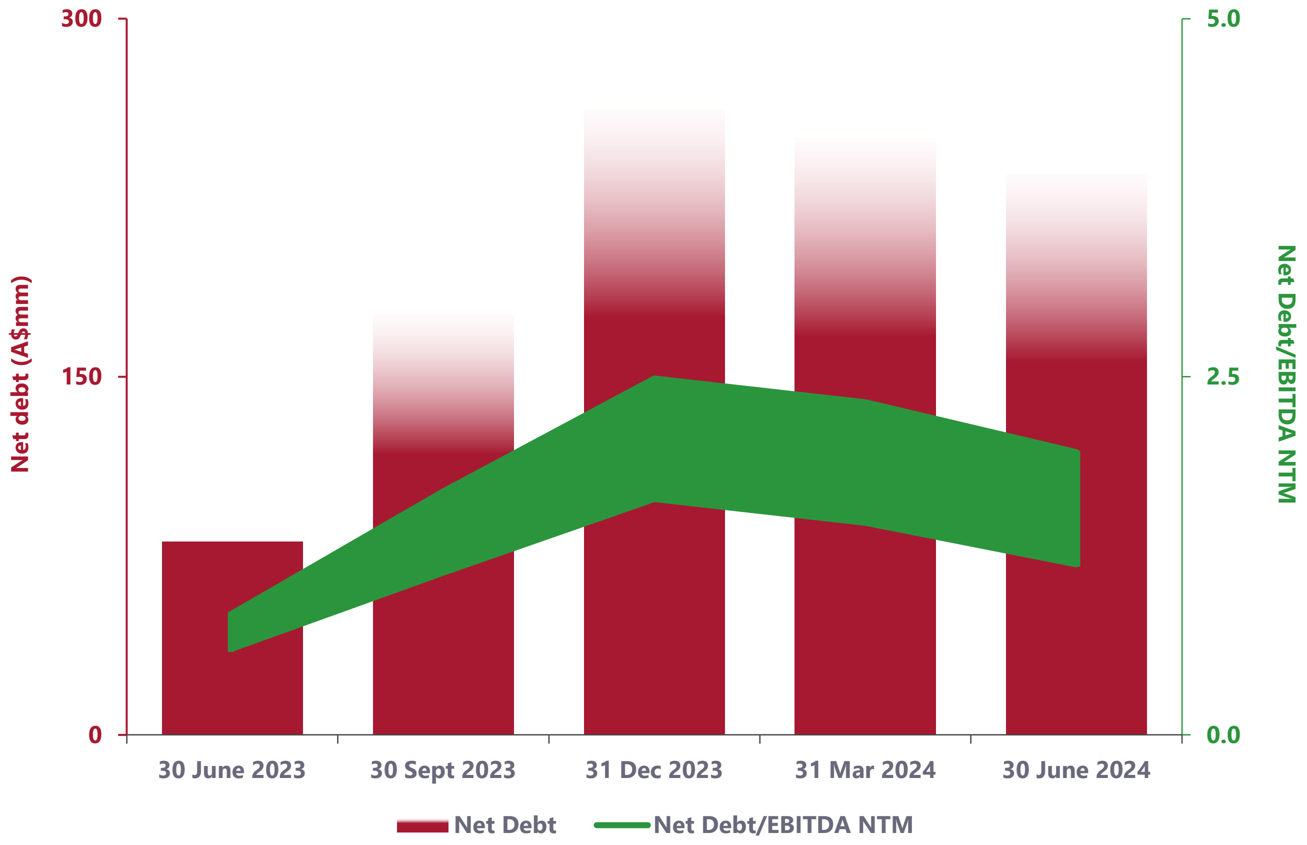
- ✓ Upstream costs remain in line with FY23
- × Higher maintenance costs, including absorber cleans
- × Engineering & technical support team (partially offset by savings in contract services)
- × Wage increases
- × General industry inflation

Opportunities for cost savings in H2 FY24 & FY25

- ✓ Less absorber cleans
- ✓ Efficiency improvements
- ✓ Savings in labour
- ✓ Corporate overhead/G&A

FY24—outlook for net debt & leverage

Peak in Q2 FY24 due to BMG wells decommissioning



- Senior secured reserve based loan (RBL)
- Strong group of eight banks
  - Mix of domestic and international banks active in the global RBL lending market
- No near term maturities
  - September 2027 expiry
  - $180mm balloon at expiry
- Additional $120mm accordion to fund growth

Operational excellence to drive improved production and cashflow

FY24 key corporate priorities

- Orbost performance improvement plan
- Delivery of BMG abandonment
- FY24 cost-out
- Positioning for growth

Orbost Gas Processing Plant

Repositioning Cooper Energy for growth

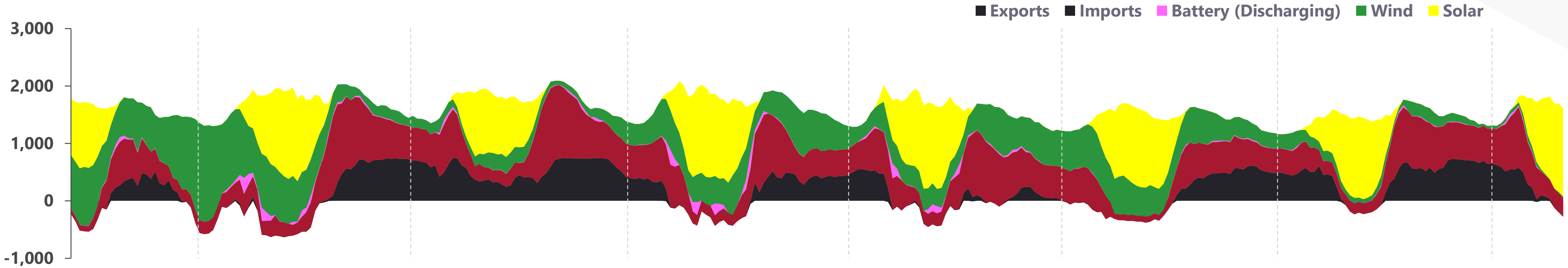
04

Appendices

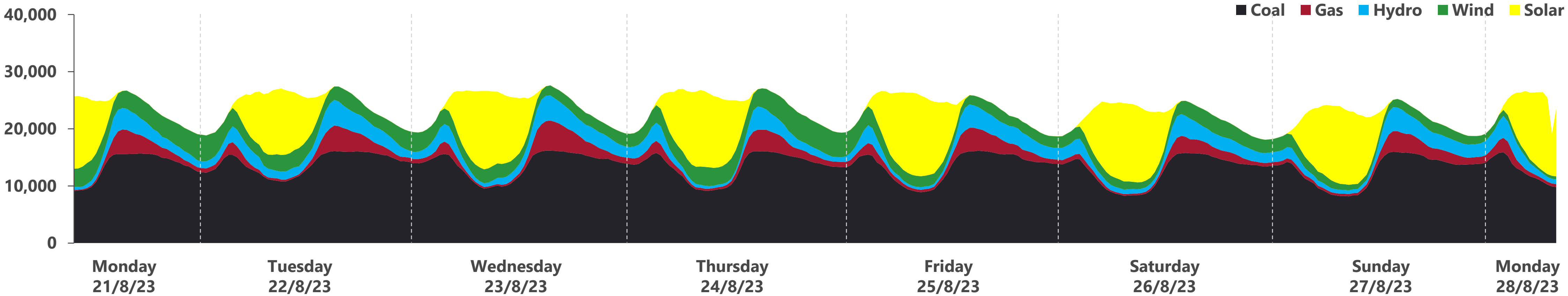
Positioned to support further integration of variable renewables

South Australia is a window into the future role of gas supply in Southeast Australia's power mix

South Australian electricity supply by type (~70% renewables annually), MW[1]



National[2] electricity supply by type (~37% renewables annually), MW[1]



Otway Basin gas hub—visible near-term growth

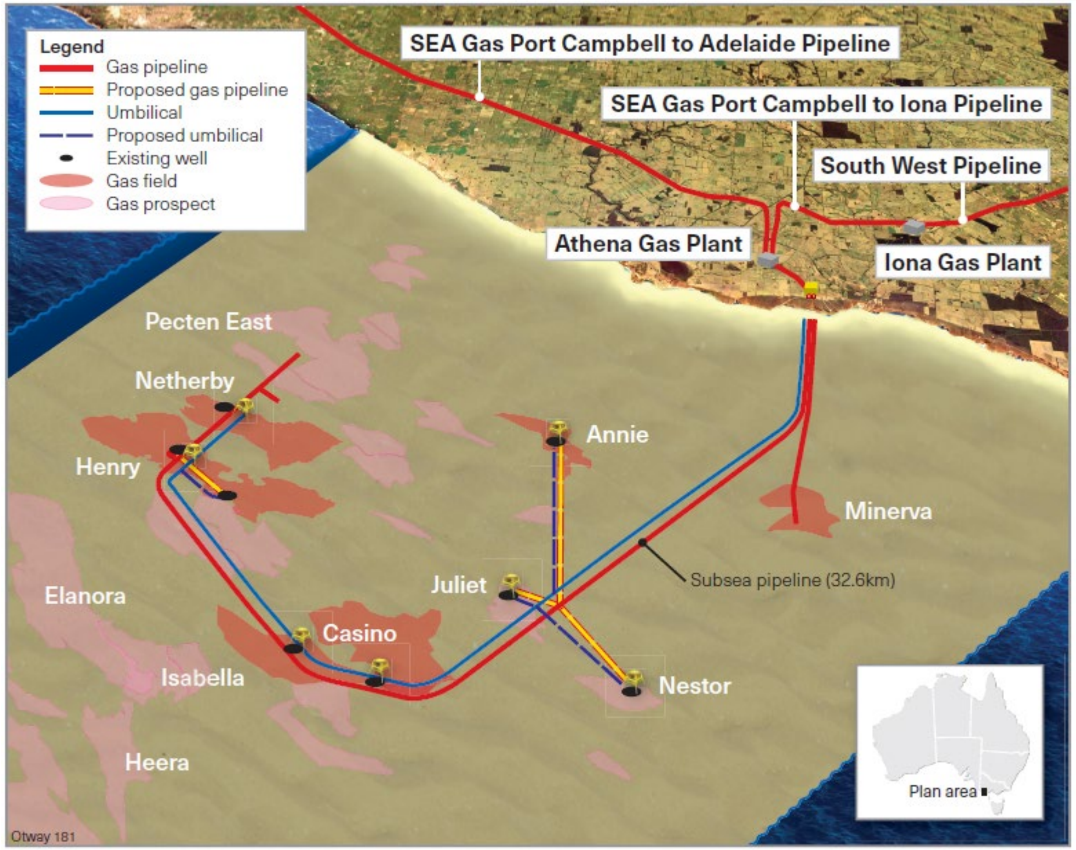
Six prospects identified with high assessed chance of geological success

Otway phase-3 development

- Development of Annie gas discovery 64.6 PJ 2C (100% basis)[1] through Athena
- Drilling campaign based around Annie + 2 low-risk exploration wells
  - Close to market and fast tie-back opportunity
- Timing of FID now subject to impact of Federal government intervention, economics and JV alignment

Mean prospective resources[2,3]

Prospect	Gross (Bcf)	COE net (Bcf)	Pg[4]	Amplitude support
Elanora	161	81	67%	✓
Isabella	149	74	70%	✓
Heera	86	43	63%	✓
Pecten East	76	38	73%	✓
Nestor	64	64	81%	✓
Juliet	49	24	84%	✓
Total	**585**	**325**		



Portfolio of high-quality prospects, close to existing infrastructure, provides next wave of growth and cash flow generation

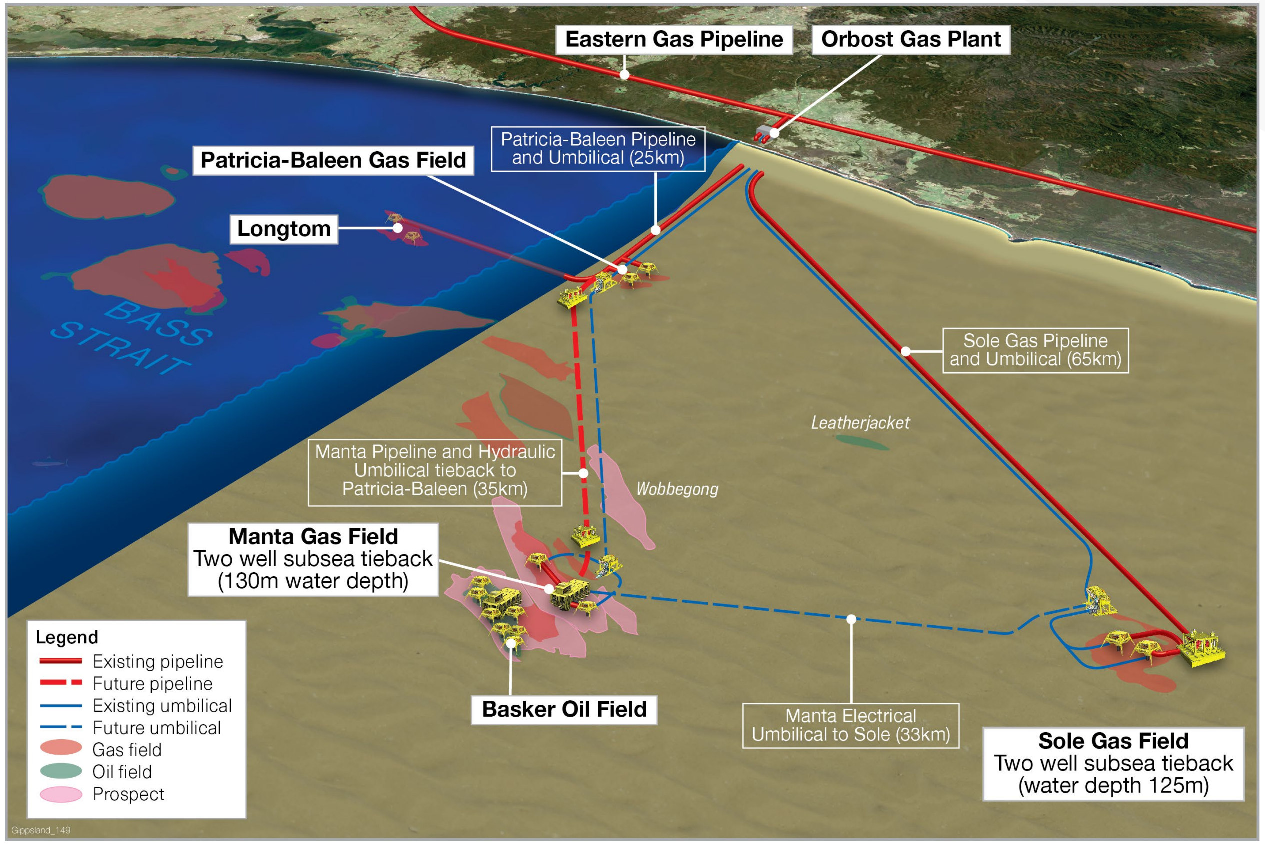
Gippsland Basin gas hub

Foundation to develop Cooper Energy's proven and prospective Gippsland gas portfolio

Manta and Gummy contingent resource estimates (COE 100% interest)[1]		1C	2C	3C
Gas	PJ	95	185	343
Condensate	MMbbl	2.5	4.9	9.7

- Future development option, COE interest 100%
- Manta-3 appraisal well planned in future campaign
- Deepening Manta-3 tests Manta Deep exploration prospect
- May utilise existing infrastructure e.g., existing pipelines to OGPP

Mean prospective resources (COE 100% interest)[2,3]		
Prospect	**COE net (Bcf)**	**Pg[4]**
Gummy Deep	401	33%
Manta Deep	414	18%
Chimaera East	250	23%
Wobbegong	242	29%

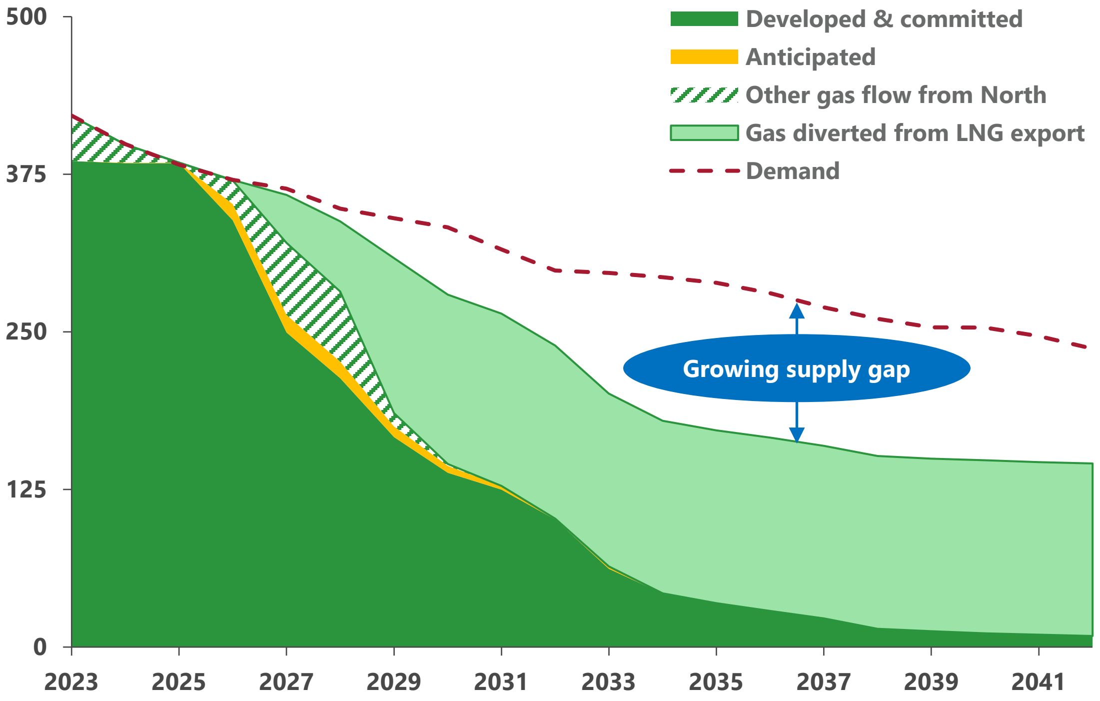


Prolific hydrocarbon basin immediately adjacent to the Southeast gas Australia market

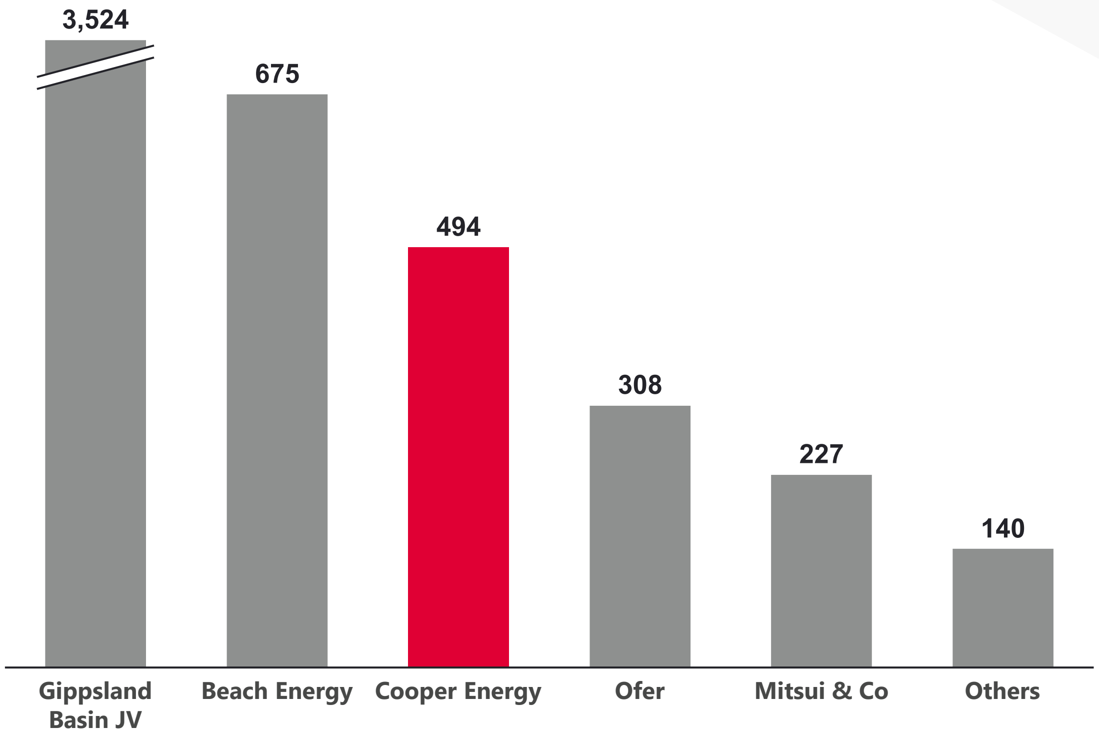
Positioned to capture long-term supply gap

Market supports long-term growth opportunities at LNG import parity

Southern states forecast supply/demand (source: AEMO), PJ/year[1]



Gippsland, Otway & Bass Basins, WM commercial reserves (PJe)[2]



Cooper Energy is the only company focused purely on the short Southeast Australia gas market and has the third largest commercial reserves[2] within the region, based on WoodMac data

Reconciliations

Underlying adjustments include restoration, OGPP reconfiguration and NOGA levy

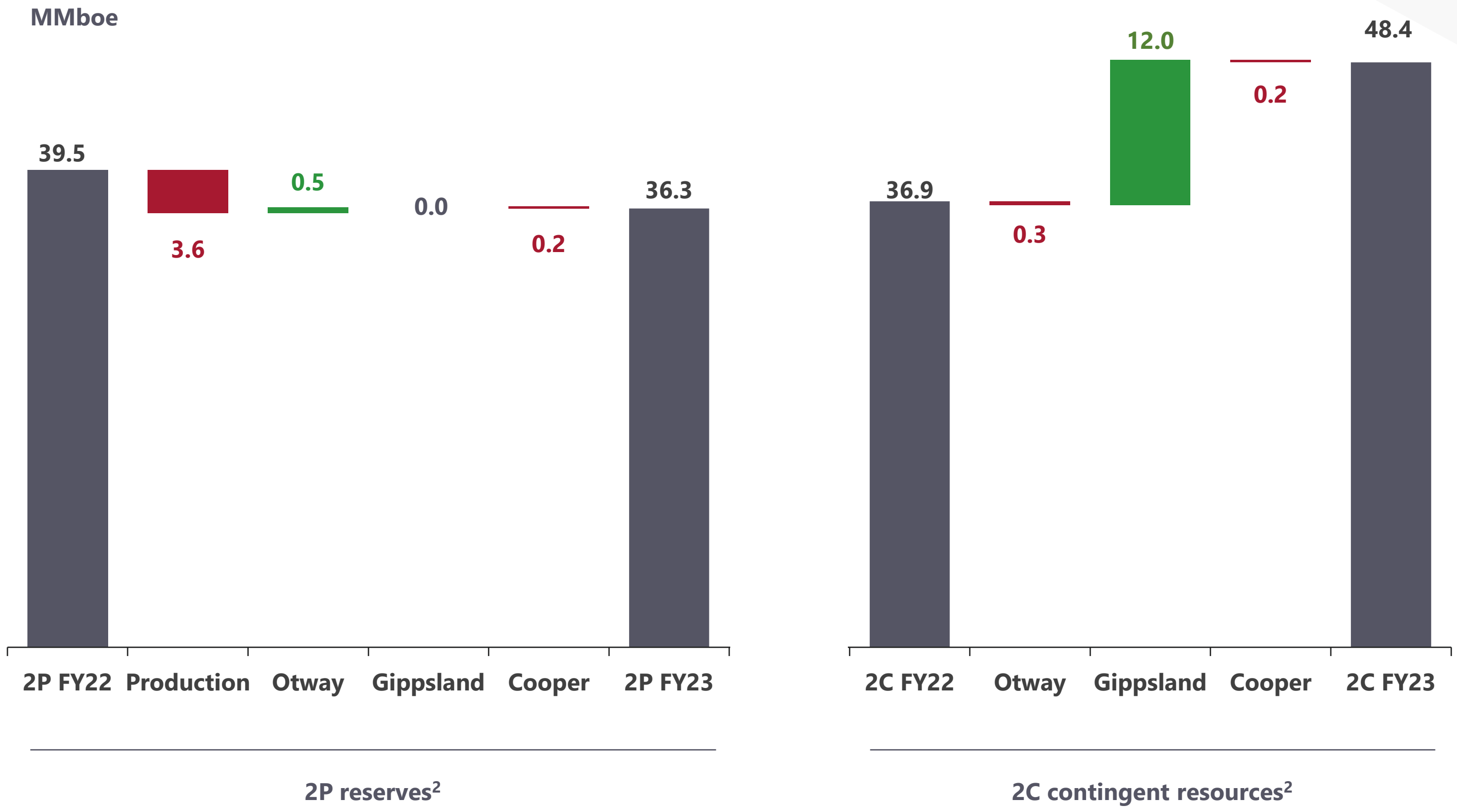
$mm	FY22	FY23
Underlying net profit / (loss) after tax	**14.4**	**(5.6)**
Adjusted for:		
Net finance costs	9.1	**8.5**
Accretion expense	4.5	**18.0**
Tax expense	(12.2)	**(36.2)**
Depreciation	3.4	**38.7**
Amortisation	50.6	**60.1**
Exploration and evaluation expense	0.2	**0.0**
Tax impact of adjustments	10.7	**25.8**
Total underlying adjustments after tax	66.3	**114.9**
Underlying EBITDAX	**80.7**	**109.3**

$mm	FY22	FY23
Statutory net profit / (loss) after tax	**(10.6)**	**(68.5)**
Adjusted for:		
Impairment		**26.1**
NOGA levy	1.6	**1.7**
Restoration expense/(income)	19.0	**46.3**
OGPP reconfiguration/commissioning	15.1	**6.2**
APA ToI		**2.9**
Leadership restructuring costs		**2.7**
Doubtful debts		**2.8**
Tax impact of adjustments	(10.7)	**(25.8)**
Total significant items after tax	25.0	**62.9**
Underlying net profit / (loss) after tax	**14.4**	**(5.6)**

June 2023 2P reserves & 2C resources[1]

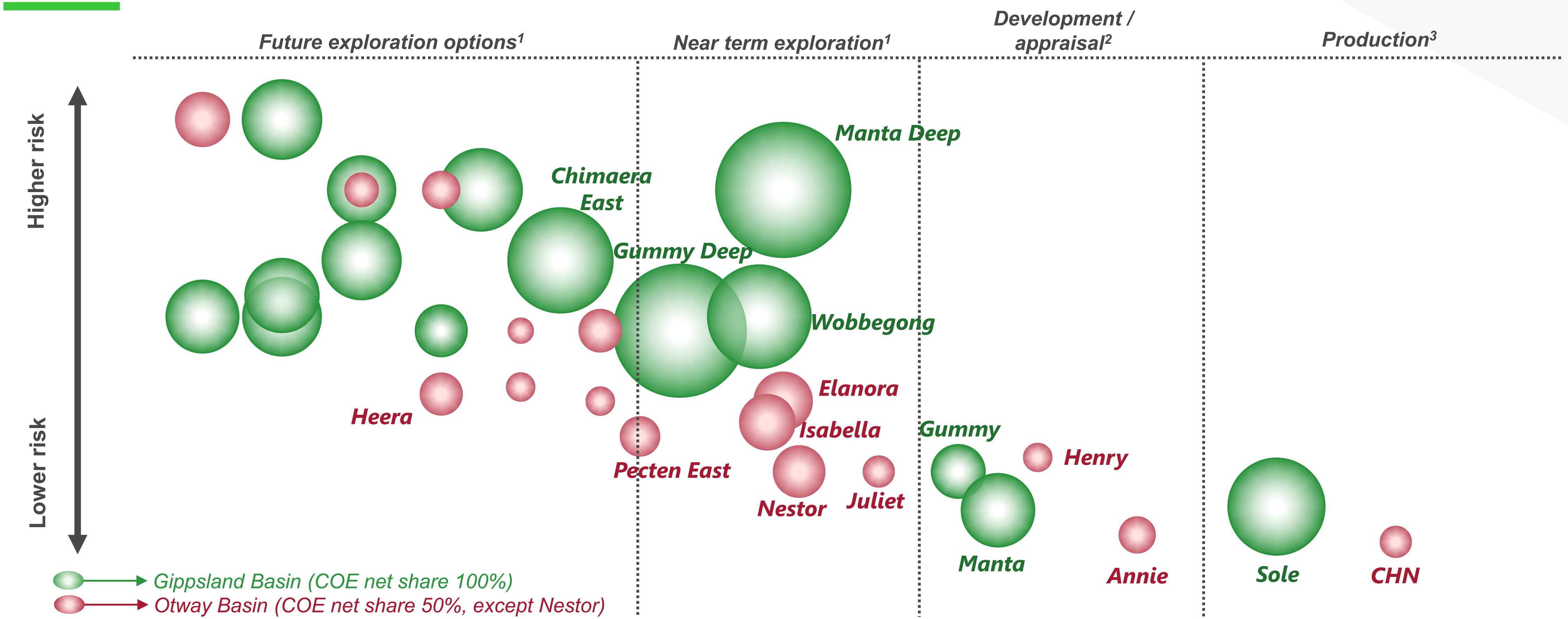
Overview

- 2P revisions
  - FY23 production
  - Extension to end of field life timing for CHN/Athena
- Sole 2P reduced by production only
- Updated assessment of Manta Hub
  - Increase of mean unrisked prospective resource potential to 1,307 Bcf of natural gas and 30 MMbbl liquids



Multiple growth opportunities within portfolio

High graded offshore exploration and appraisal prospects to backfill existing infrastructure



36 MMboe 2P reserves, 48 MMboe 2C resources and >1Tcf mean resource potential, close to market, and with a clear pathway to commercialisation via operated gas plants (Athena 150 TJ/d, OGPP 68 TJ/d)

Reserves and Contingent Resources at 30 June 2023

Reserves[1]		1P (Proved)				2P (Proved & Probable)				3P (Proved, Probable & Possible)			
		Cooper	Otway	Gippsland	Total	Cooper	Otway	Gippsland	Total	Cooper	Otway	Gippsland	Total
Developed													
Sales gas	PJ	0.0	16.0	132.5	148.6	0.0	19.5	195.2	214.7	0.0	20.4	276.8	297.1
Oil + condensate	MMbbl	0.3	0.0	0.0	0.3	0.7	0.0	0.0	0.8	1.1	0.0	0.0	1.1
Developed total (1)	**MMboe**	**0.3**	**2.6**	**21.7**	**24.6**	**0.8**	**3.2**	**31.9**	**35.9**	**1.1**	**3.3**	**45.2**	**49.7**
Undeveloped													
Sales gas	PJ	0.0	3.3	0.0	3.3	0.0	2.5	0.0	2.5	0.0	2.6	0.0	2.6
Oil and condensate	MMbbl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1
Undeveloped total	**MMboe**	**0.0**	**0.5**	**0.0**	**0.6**	**0.1**	**0.4**	**0.0**	**0.5**	**0.1**	**0.4**	**0.0**	**0.5**
Total	**MMboe**	**0.3**	**3.2**	**21.7**	**25.2**	**0.8**	**3.6**	**31.9**	**36.3**	**1.1**	**3.8**	**45.2**	**50.2**

(1) The conversion factor 1 PJ = 0.163 MMboe has been used to convert from Sales Gas (PJ) to oil equivalent (MMboe) for the Otway and Gippsland basins.
(2) 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.

Contingent Resources[1]	1C			2C			3C		
	Gas PJ	Oil and cond. MMbbl	Total MMboe	Gas PJ	Oil and cond. MMbbl	Total MMboe	Gas PJ	Oil and cond. MMbbl	Total MMboe
Gippsland Basin	100.9	2.5	19.0	198.9	4.9	37.4	365.0	9.7	69.3
Otway Basin	42.8	0.0	7.0	64.8	0.1	10.7	84.1	0.1	13.9
Cooper Basin	0.0	0.3	0.3	0.0	0.3	0.3	0.0	0.5	0.5
Total	**143.8**	**2.9**	**26.4**	**263.7**	**5.3**	**48.4**	**449.0**	**10.3**	**83.7**

Notes on calculation of Reserves and Contingent Resources

Cooper Energy prepares its petroleum Reserves and Contingent Resources in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

The estimates of petroleum Reserves and Contingent Resources contained in this Reserves statement are as at 30 June 2023. The Company is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Unless otherwise stated, all references to Reserves and Contingent Resource quantities in this document are net to Cooper Energy.

Cooper Energy has completed its own estimation of Reserves and Contingent Resources for its operated Otway and Gippsland Basin assets. Elsewhere, Reserves and Contingent Resource estimations are based on assessment and independent views of information provided by the permit operators (Beach Energy Limited for PEL 92).

Reference points for Cooper Energy's petroleum Reserves and Contingent Resources and production are defined points where normal operations cease, and petroleum products are measured under defined conditions prior to custody transfer. Fuel, flare and vent consumed prior to the reference point is excluded.

Petroleum Reserves and Contingent Resources are prepared using deterministic, with support from probabilistic, methods. The Reserves and Contingent 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.

Throughout this announcement, totals may not exactly reflect arithmetic addition due to rounding.

The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). Condensate and crude oil are converted at 1bbl = 1 boe. The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert Oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe).

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 and Netherby). The Cooper Basin totals comprise the arithmetically aggregated PEL 92 fields. The Gippsland Basin totals comprise Sole Reserves only.

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.

Cooper Energy has undertaken this Contingent Resource assessment using probabilistic resource estimation for the Golden Beach Sub-Group reservoirs in the Gummy field. This methodology incorporates a range of uncertainty relating to each key reservoir input parameter to predict the likely range of outcomes. This approach is consistent with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

Analytical procedures used to assess Contingent Resources were:

- interpretation of 2020 CGG Gippsland Multi-client 3D seismic data;
- detailed time/depth conversion;
- petrophysical and hydrocarbon analysis from the wells drilled in the area;
- interpretation of fluid contacts and ranges in reservoir deliverability;
- probabilistic assessment of subsurface uncertainties and statistical ranges for gas-initially-in-place estimates; and
- estimation of range in ultimate recoverable volumes generated via P90, P50 and P10 GAP-MBal models based on a field development scenario.

The Contingent Resources within VIC/RL13, VIC/RL14 and VIC/RL15 are currently assessed to be contingent because the evaluation of the commerciality of a future development project is incomplete.

This is Cooper Energy Limited's first reported Contingent Resource estimate for the hydrocarbon-bearing reservoirs, already discovered with the Gummy field. The resource classification given to the Contingent Resource estimates concerning the Gummy field (described above) is "Development Unclarified".

Qualified petroleum Reserves and resources evaluator statement

The information contained in this report regarding Cooper Energy's Reserves and Contingent Resources is based on, and fairly represents, information and supporting documentation reviewed prepared by, or under the supervision of, Mr Andrew Thomas who is a full-time employee of Cooper Energy Limited holding the position of Chief Exploration and Subsurface Officer. Mr Thomas 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.

Abbreviations

$	Australian dollars
APA	APA Group (ASX: APA)
ASX	Australian Securities Exchange
bbl	Barrels
Bcf	Billion cubic feet of gas
Cooper Energy or Company	Cooper Energy Limited ABN 93 096 170 295
FEED	Front End Engineering and Design
FID	Final Investment Decision
GSA	Gas Sales Agreement
kbbl	Thousand barrels
MMboe	Million barrels of oil equivalent
n/m	Not meaningful
OGPP	Orbost Gas Processing Plant
PEL	Petroleum Exploration Licence
PEP	Petroleum Exploration Permit
PJ	Petajoules
Shares	Fully paid ordinary shares in the capital of the Company
Transaction or Acquisition	Cooper Energy's acquisition of all the assets comprising the Orbost gas Processing Plant
TJ	Terajoules
YTD	Year to date

Footnotes

By page

Slide 4
1. TRIFR is recordable incidents (Medical Treatment Injuries + Restricted Work/Transfer Case + Lost Time Injuries + Fatalities) per million hours worked. Calculated on a rolling 12-month basis
2. Organisational carbon emissions voluntarily fully offset for FY23. These consist of Scope-1 (direct), Scope-2 (purchased electricity) and relevant Scope-3 emissions (embedded energy and business travel). Downstream Customer Scope-3 transportation and combustion emissions are not included

Slide 5
1. TRIFR is recordable incidents (Medical Treatment Injuries + Restricted Work/Transfer Case + Lost Time Injuries + Fatalities) per million hours worked. Calculated on a rolling 12-month basis
2. Per million hours worked
3. Industry TRIFR is the NOPSEMA benchmark for offshore Australian operations; data is updated 6-monthly; published at www.nopsema.gov.au

Slide 7
1. 47.9 TJ/d excluding planned shutdown

Slide 8
1. From 1 July 2021 – 15 December 2021, CHN gas was processed at the Iona Gas Plant

Slide 13
1. Equivalent to FY23: 3.56 MMboe (FY22: 3.31 MMboe)
2. Includes $178mm being the institutional portion of the $244mm equity raise. The retail portion was received on 14 July 2022

Slide 15
1. OGPP Acquisition relates cash flows consist of proceeds from equity issue of $57.6mm, OGPP purchase consideration of $210.0mm, stamp duty & acquisition costs of $27.0mm and finance & other costs of $15.1mm

Slide 21
1. Equivalent to 3.5 – 3.9 MMboe
2. Production expenses comprise labour, materials, transport, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases and trading costs, royalties and non-cash depreciation and amortisation
3. Capital expenditure guidance includes stay in business capex and BMG abandonment costs

Slide 22
1. Production expenses comprises labour, materials, transport, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases and trading costs, royalties and non-cash depreciation and amortisation

Slide 26
1. www.opennem.org.au
2. National electricity supply refers to the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

Slide 27
1. Annie 2C resource included as part of the Otway Basin 2C number in the FY22 Reserves and Contingent Resources ASX release on the 22nd August 2022
2. Prospective Resources of the unrisked volume estimated to be recoverable from the prospect attributable to the Cooper Energy joint venture interest . The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations
3. Mean Prospective Resource for the Otway prospects was announced to the ASX on 9 February 2022
4. Pg represents the estimated probability of finding moveable gas

Slide 28
1. Contingent Resource for the Manta gas and liquids resource was announced to ASX on 12 August 2019, Contingent Resource for Gummy gas and liquids resource was announced to ASX on 25 August 2023
2. Prospective Resources of the unrisked volume estimated to be recoverable from the prospect attributable to the Cooper Energy joint venture interest. The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations
3. Prospective resources for Gummy Deep, Manta Deep, Chimaera East and Wobbegong were announced to the ASX on 15 May 2023
4. Pg represents the estimated probability of finding moveable gas

Footnotes

By page

Slide 29

1. Cooper Energy analysis of 2023 AEMO GSOO Report
2. Wood Mackenzie Upstream Australasia Insight Report (July 2021). Amounts shown here are Wood Mackenzie assessed commercial reserves. Wood Mackenzie Disclaimer: The data and information provided by Wood Mackenzie should not be interpreted as advice and you should not rely on it for any purpose. You may not copy or use this data and information except as expressly permitted by Wood Mackenzie in writing. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for your use of this data and information except as specified in a written agreement you have entered into with Wood Mackenzie for the provision of such data and information.

Slide 31

1. Refer reserves and contingent resources at 30 June 2023 announced to the ASX on 25 August 2023
2. Totals may not reflect arithmetic addition due to rounding

Slide 32

1. Bubble size of exploration prospects is based on unrisked mean recoverable resource estimate (Cooper Energy net share)
2. Bubble size of Henry, Manta, Gummy and Annie bubble size is based on 2C Contingent Resources estimate (Cooper Energy net share) at 30 June 2023
3. Bubble size of Casino-Henry-Netherby (CHN) and Sole is based on 2P Reserves estimate (Cooper Energy net share) at 30 June 2022

Slide 33

1. Contingent Resources were announced to the ASX on 22 August 2023. 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. The conversion factor of 1 PJ = 0.163 MMboe has been used to convert from Sales Gas (PJ) to Oil Equivalent (MMboe). The Contingent Resources information displayed should be read in conjunction with the information provided in the Notes on calculation of Reserves and Contingent Resources provided on the following slide