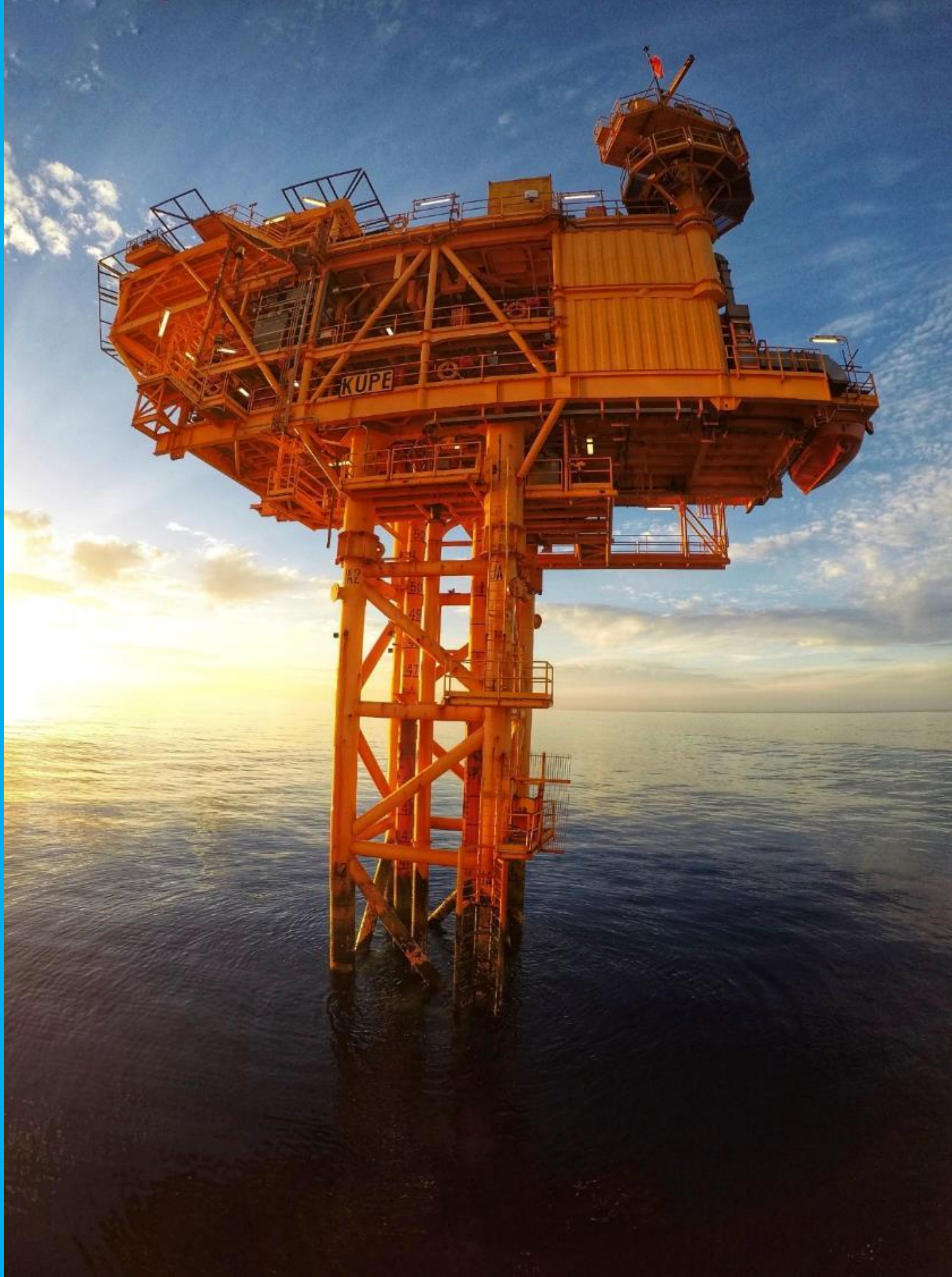
17 AUGUST 2020

FY20 FULL YEAR RESULTS AND OUTLOOK PRESENTATION



Compliance statements

Disclaimer

This presentation contains forward looking statements that are subject to risk factors associated with oil, gas and related businesses. It is believed that the expectations reflected in these statements are reasonable but they may be affected by a variety of variables and changes in underlying assumptions which could cause actual results or trends to differ materially, including, but not limited to: COVID-19 risks, price fluctuations, actual demand, currency fluctuations, drilling and production results, reserve estimates, loss of market, industry competition, environmental risks, physical risks, legislative, fiscal and regulatory developments, economic and financial market conditions in various countries and regions, political risks, project delays or advancements, approvals and cost estimates. Please refer to the Directors' Report in the FY20 annual report for more details specifically relating to COVID-19 risks.

Underlying EBITDAX (earnings before interest, tax, depreciation, amortisation, evaluation, exploration expenses and impairment adjustments), underlying EBITDA (earnings before interest, tax, depreciation, amortisation, evaluation and impairment adjustments), underlying EBIT (earnings before interest, tax, and impairment adjustments) and underlying profit are non-IFRS financial information provided to assist readers to better understand the financial performance of the underlying operating business. They have not been subject to audit or review by Beach's external auditors. The information has been extracted from the audited financial statements.

Free cash flow in this presentation is defined as cash flows from operating activities plus cash flows from investing activities less cash flows from acquisitions and divestments less lease liability payments.

All references to dollars, cents or $ in this presentation are to Australian currency, unless otherwise stated. References to "Beach" may be references to Beach Energy Limited or its applicable subsidiaries. Unless otherwise noted, all references to reserves and resources figures are as at 30 June 2020 and represent Beach's share.

References to planned activities in FY21 and beyond FY21 may be subject to finalisation of work programs, government approvals, joint venture approvals and board approvals.

Due to rounding, figures and ratios may not reconcile to totals throughout the presentation.

Authorisation

This release has been authorised for release by Matt Kay, Managing Director and CEO of Beach Energy.

Assumptions

The five year outlook set out in this presentation is not guidance. The outlook is uncertain and subject to change. The outlook has been estimated on the basis of the following assumptions: 1. a US$41.25/bbl Brent oil price in FY21, a US$52.50/bbl Brent oil price in FY22 and US$60/bbl Brent oil price from FY23; 2. 0.70 AUD/USD exchange rate; 3. various other economic and corporate assumptions; 4. assumptions regarding drilling results; and 5. expected future development, appraisal and exploration projects being delivered in accordance with their current expected project schedules.

FY21 guidance is uncertain and subject to change. FY21 guidance has been estimated on the basis of the following assumptions: 1. a US$41.25/bbl Brent oil price; 2. 0.70 AUD/USD exchange rate; 3. various other economic and corporate assumptions; 4. assumptions regarding drilling results; and 5. expected future development, appraisal and exploration projects being delivered in accordance with their current expected project schedules.

These future development, appraisal and exploration projects are subject to approvals such as government approvals, joint venture approvals and board approvals. Beach expresses no view as to whether all required approvals will be obtained in accordance with current project schedules.

Reserves disclosure

Beach prepares its petroleum reserves and contingent resources estimates in accordance with the 2018 update to the Petroleum Resources Management System (PRMS) published by the Society of Petroleum Engineers.

The reserves and resources information in this report is based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr David Capon (General Manager Development - Victoria, New Zealand and NT). Mr Capon is a full time employee of Beach Energy Limited and has a BSc (Hons) degree from the University of Adelaide and is a member of the Society of Petroleum Engineers. He has in excess of 25 years of relevant experience. The reserves and resources information in this presentation has been issued with the prior written consent of Mr Capon as to the form and context in which it appears.

Beach confirms that it is not aware of any new information or data that materially affects the information included in this report and that all the material assumptions and technical parameters underpinning the estimates in the aforesaid market announcement continue to apply and have not materially changed.

Conversion factors used to evaluate oil equivalent quantities are sales gas and ethane: 5.816 TJ per kboe, LPG: 1.398 bbl per boe, condensate: 1.069 bbl per boe and oil: 1 bbl per boe. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated net of fuel, flare & vent and third party royalties.

Our purpose

"Sustainably deliver energy for communities"

COVID-19 impact

FY20 was a tale of two halves

At FY20 half year results

On track to deliver growth program prior to COVID-19 impact:

- ✓ 105 wells drilled in H1 at 83% success rate
- ✓ Beharra Springs Deep 1 exploration success
- ✓ Bauer appraisal drilling identifies field extension
- ✓ Spudded Black Watch 1, first new well to supply Otway Gas Plant in more than 4 years
- ✓ On track to deliver full year production and EBITDA within initial guidance

COVID-19 impact on

HSER

- Rapid response to protect staff, contractors, assets
- Border restrictions impact workforce travel arrangements

Commodity prices and demand

- Rapid decline in oil prices in H2
- Brent at US$18/bbl in March
- H2 FY20 revenues 17% below H1
- Significant reduction in global oil/LNG demand

Supply chain

- Disruption of supply chain from global sources
- Issues obtaining components for major equipment

COVID-19 risks mitigated via

Balance sheet strength at 30 June 2020

- $50 million net cash and $500 million liquidity

Low cost operator

- Implemented staff and contractor reductions
- Lowering field operating cost, down 3% than FY19
- $30 million cost reduction achieved in FY20 vs FY18

High returning assets

- ROCE >19%
- Reserves robust at lower oil prices
- Revenue certainty: Gas revenues exceeds total operating costs plus Stay In Business capex[1]

Actively controlling our planned investment activities

- Reduced FY21 capital expenditure by >30%
- Actively controlling our work program

Refer to disclaimer on slide 2 regarding risks associated with forward looking statements, including COVID-19 risks

1. Excludes oil tolls, tariffs and royalties.

Beach Response to COVID-19

The Journey

Crisis Management Team → Business Continuity Team → Office Staff Transitioned to Work from Home → COVID-19 Site Specific Procedures → Emergency Response Exercises and Assurance → Partial Return to Office

Crisis Management Team

Activated 20 February

- Crisis Management activated due to potential pandemic
- Health Response Team engaged
- Instituted travel restrictions increased hygiene controls

Business Continuity Team

Activated 12 March

- Activated full-time, multi-discipline Business Continuity Team
- 20+ Team Members
- 8 Work Streams across all Core Business Divisions

Office Staff Transitioned to Work from Home

Commenced 20 March

- All office based personnel working from home
- Electronic COVID-19 self-assessment form available via mobile phone

COVID-19 Site Specific Procedures

Activated 20 March

- COVID-19 Plans in place at all operational sites
- Plans include: Hygiene, social distancing, case management, isolation, evacuation and assurance protocols

Emergency Response Exercises and Assurance

Commenced 1 June

- Emergency response exercises completed at all sites
- Developed and implemented an assurance programme to verify controls

Partial Return to Office

Focus moving forward

- Rostered return to offices for SA, WA and NZ.
- Vic still working at home
- Monitoring and working with Govt, regulators and supply chain on COVID management

Summary

A high margin and high growth business

Solid FY20 result in challenging conditions

- ✓ Responded quickly to COVID-19 threat
- ✓ 178 wells drilled at 81% overall success rate
- ✓ FY20 production 26.7 MMboe, within 1% of guidance
- ✓ FY20 underlying EBITDA of $1,108 million
- ✓ FY20 underlying NPAT of $461 million
- ✓ ROCE >19%
- ✓ Final dividend of 1.0 cent per share

Entering FY21 with a strong foundation

- ✓ **Balance sheet in net cash position**
- ✓ **High margin business** – no impairments of producing assets at reduced long term oil price outlook[1] (US$60/bbl)
- ✓ **Resilient and growing 2P reserves base**
  - 352 MMboe 2P reserves
  - 214% 2P reserves replacement ratio[2] in FY20
  - 2P reserves life increased to 13.2 years
  - 2P reserves resilient at lower oil prices
- ✓ **Gas business provides material revenue certainty**

Actively controlled investment program

- ✓ Planned FY21 capital expenditure reduced by >30%
- ✓ Prudent slow down in investment activity to reflect COVID-19 risks and uncertainty
- ✓ **New rig contract signed with Diamond Offshore**, drilling planned to commence Dec '20 – Mar '21
- ✓ **Waitsia Stage 2 FID in December 2020 quarter** with LNG export of up to 1.5 mtpa via NWS
- ✓ Ironbark 1 exploration well to spud in Q2 FY21
- ✓ **Beach can invest through the cycle**. Forecast peak net gearing <10% at US$30/bbl over next 5 years
- ✓ **Targeting 37 – 43 MMboe production in FY25**
- ✓ **$2.1 billion forecast 5 year FCF at reduced commodity price outlook[1]**

1. Refer to slide 2 for information relating to assumptions
2. Organic 2P reserves replacement ratio is defined as 2P reserves additions, excluding acquisitions and divestments, for the period divided by reported production for the same period

Looking back over FY19/20

Track record of delivery on journey to date

	Total FY19 + FY20 guidance[1]	Total FY19 + 20 results	Met (✓) or Exceeded (✓ ✓)
Production (MMboe)	53–57	**56.1**	✓
Capex ($ million)	1,210–1,390	**1,310**	✓
Free Cash Flow ($ million)	310	**437**	✓ ✓
2P reserves replacement ratio	>100%	**209%**	✓ ✓
ROCE (average)	17–20%	**23%**	✓ ✓

Ahead of plan in FY19/20. Pace actively moderated given external challenges

1. Production and capex guidance was released to the ASX at the FY18 and FY19 full year results. Free Cash Flow guidance represents the sum of FY19 FCF outlined at the September 2018 investor briefing and FY20 FCF outlook provided at the FY19 full year results in August 2019. 2P reserves replacement and ROCE targets were released to the ASX at the September 2018 Investor Briefing.

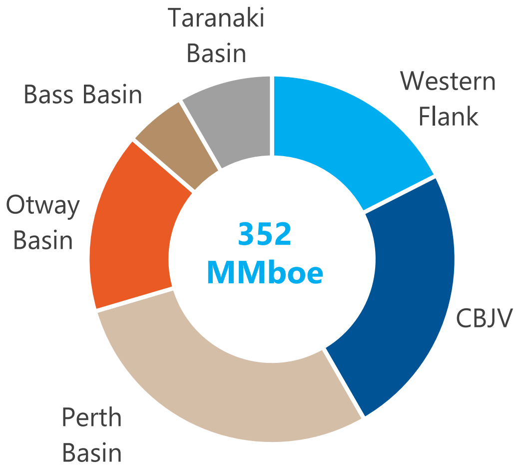
Reserves and contingent resources

Organic 2P reserves replacement above 200% for three straight years

Summary of reserves at 30 June 2020 (developed plus undeveloped, net to Beach)

(MMboe)	FY19	FY20	
1P reserves	201	**202**	+1%
2P reserves	**326**	**352**	**+8%**
3P reserves	514	**576**	+12%
2C contingent resources	185	**180**	(2%)

2P reserves



Highlights

- ✓ 2P reserves increased by 8% from 326 MMboe to 352 MMboe
- ✓ 214% organic 2P reserves replacement ratio[1]
- ✓ 263% organic 2P reserves replacement ratio[1] average FY18-20
- ✓ 2P reserves life increased from 12.4 years to 13.2 years
- ✓ Initial 2P reserves booking for Beharra Springs Deep of 29 MMboe
- ✓ 159% 2P reserves replacement in Western Flank Oil
- ✓ Reserves includes impact of sale of interest in La Bella and Beharra Springs
- ✓ 75% of 2P reserves independently audited in FY20
- ✓ Long term oil price assumption reduced in-line with consensus forecasts
- ✓ **As a sensitivity, a further 20% reduction in commodity (oil and gas) price assumptions would reduce 2P reserves by less than 3%**

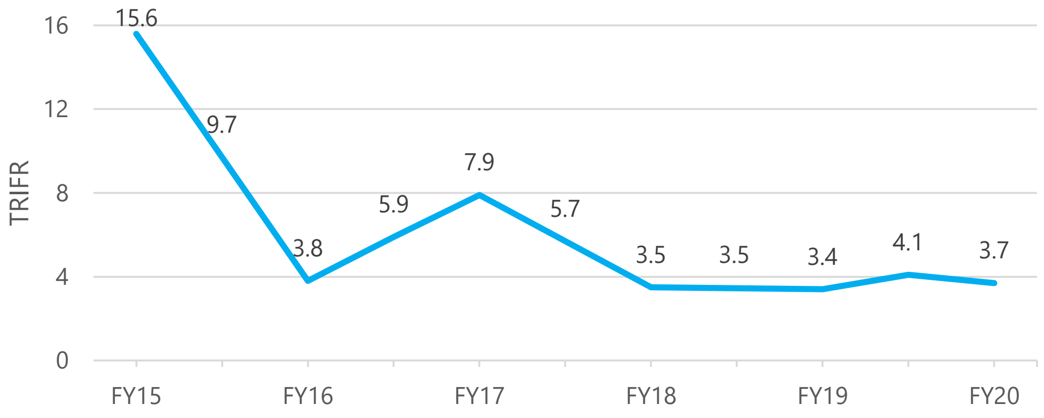
Refer to Compliance Statement slides for reserves disclosures.

1. Organic 2P reserves replacement ratio is defined as 2P reserves additions, excluding acquisitions and divestments, for the period divided by reported production for the same period.

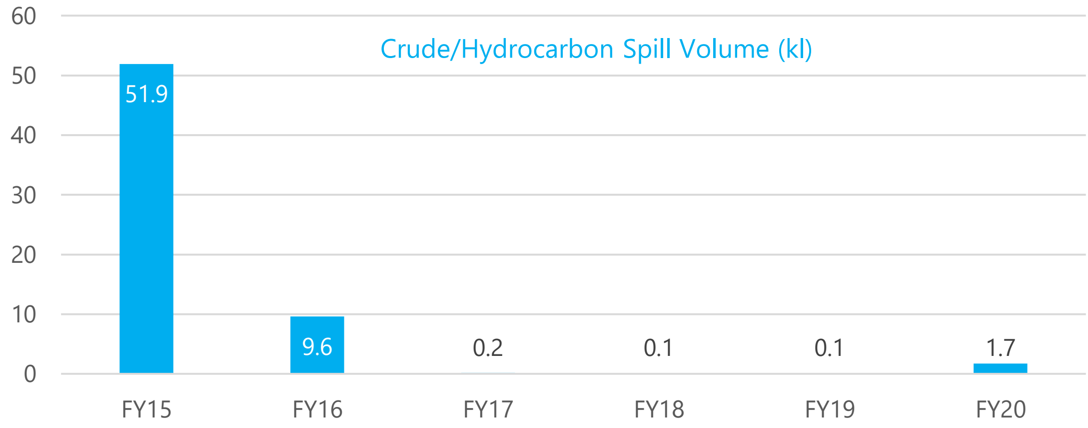
Beach Energy HSE performance

Strong performance despite COVID-19 challenges

Safety performance



Environmental performance[2]



Focus on improving HSE performance

Safety

- Improved safety performance in H2 FY20
- No recordable HSE incidents in Victoria and NZ for FY20

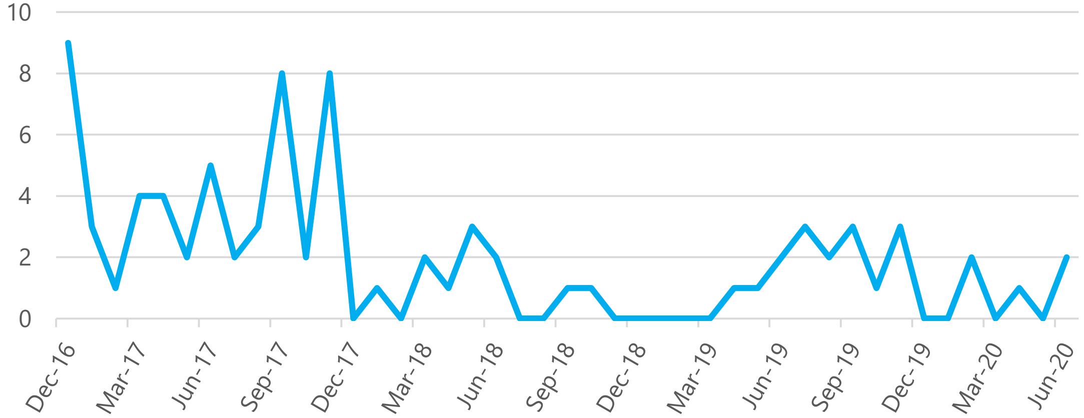
Environment

- Spill volumes remained low with record levels of activity

Process Safety

- No material gas releases

Process safety - loss of containment[1]



1. Based on API 754 Tier 1, 2, 3.4 modified.
2. Metric extended in FY20 to include all hydrocarbon spills to grade.

Sustainability

Beach releases new emissions targets

- Beach remains committed to a lower carbon future
- Emissions benchmarking undertaken at all sites
- Board approved emissions reduction target of 25% CO2e by FY25 relative to FY18 benchmark levels[1]
- Portfolio tested against carbon price of up to $50/tonne CO_2e[2]
- No material financial impacts from targeted emissions reductions
- Further emissions reductions projects to be screened in FY21
- Carbon Capture and Storage potential being evaluated

Solar panels at Port Bonython. Photo courtesy Santos

1. Against current portfolio.
2. The carrying value of Australian producing assets was assessed against NPVs including a carbon pricing slope ranging from $25/tCO2e and increasing to $50/tCO2e by 2040 (real).

FY20 FULL YEAR RESULTS AND OUTLOOK PRESENTATION

Financial Results

FY20 financial summary

A net cash, high margin, high returning business

FY20 results

- ✓ FY20 underlying NPAT $461 million
- ✓ Underlying EBITDA margin 67%
- ✓ ROCE 19%
- ✓ $874 million operating cash flow

Balance sheet and asset quality

- ✓ $50 million net cash
- ✓ $500 million liquidity
- ✓ No producing asset impairments at lower long term oil price assumptions
- ✓ 2P reserves remain economic at lower commodity prices

Revenue stability

- ✓ Over $600 million in sales gas and ethane revenues
- ✓ >99% of gas sold under contract
- ✓ Gas contract pricing fixed or with downside protection
- ✓ Gas revenues cover all operating costs and SIB costs[1]

Targeting further cost reductions

- ✓ $30 million pa direct controllable operating cost reduction achieved
- ✓ Workforce optimised for modified forward work program
- ✓ Further reduction in field operating cost/boe targeted in FY21
- ✓ Reviewing all contracts to identify areas of further cost savings

1. Excludes oil tolls, tariffs and royalties.

Financial highlights

$ million (unless otherwise indicated)	FY19	FY20	Change
Production (MMboe)	29.4	**26.7**	⬇ 9%
Pro Forma Production[1] (MMboe)	26.2	**26.7**	⬆ 2%
Sales volumes (MMboe)	31.2	**27.7**	⬇ 11%
Avg. realised oil price ($/bbl)	101.8	**80.9**	⬇ 21%
Avg. realised gas/ethane price ($/GJ)	6.81	**7.29**	⬆ 7%
Sales revenue	1,925	**1,650**	⬇ 14%
Underlying EBITDA	1,375	**1,108**	⬇ 19%
Underlying EBITDA margin	71%	**67%**	⬇
Net profit after tax	577	**501**	⬇ 13%
Underlying NPAT[2]	560	**461**	⬇ 18%
Operating cash flow	1,038	**874**	⬇ 16%
ROCE	27%	**19%**	⬇
Net (debt)/cash	172	**50**	⬇ 71%

Underlying EBITDA (⇩19%)

- FY19 Otway sale impacted production and sales volumes, with production 2% higher on pro forma basis
- 21% decrease in realised oil price, partly offset by a 7% increase in realised gas and ethane prices
- Inclusion of $48 million unwind of GSA liability
- Inclusion of $21 million Tawhaki 1 exploration well cost

Operating cash flow (⇩ 16%)

- 16% decrease in operating cash flow driven by 14% reduction in sales revenue and $134 million increase in cash tax payments, partly offset by a 9% reduction in cash cost of sales

Beach remains in net cash position at year end

- $50 million net cash at 30 June 2020
- Final dividend of 1.0 cent per share fully franked

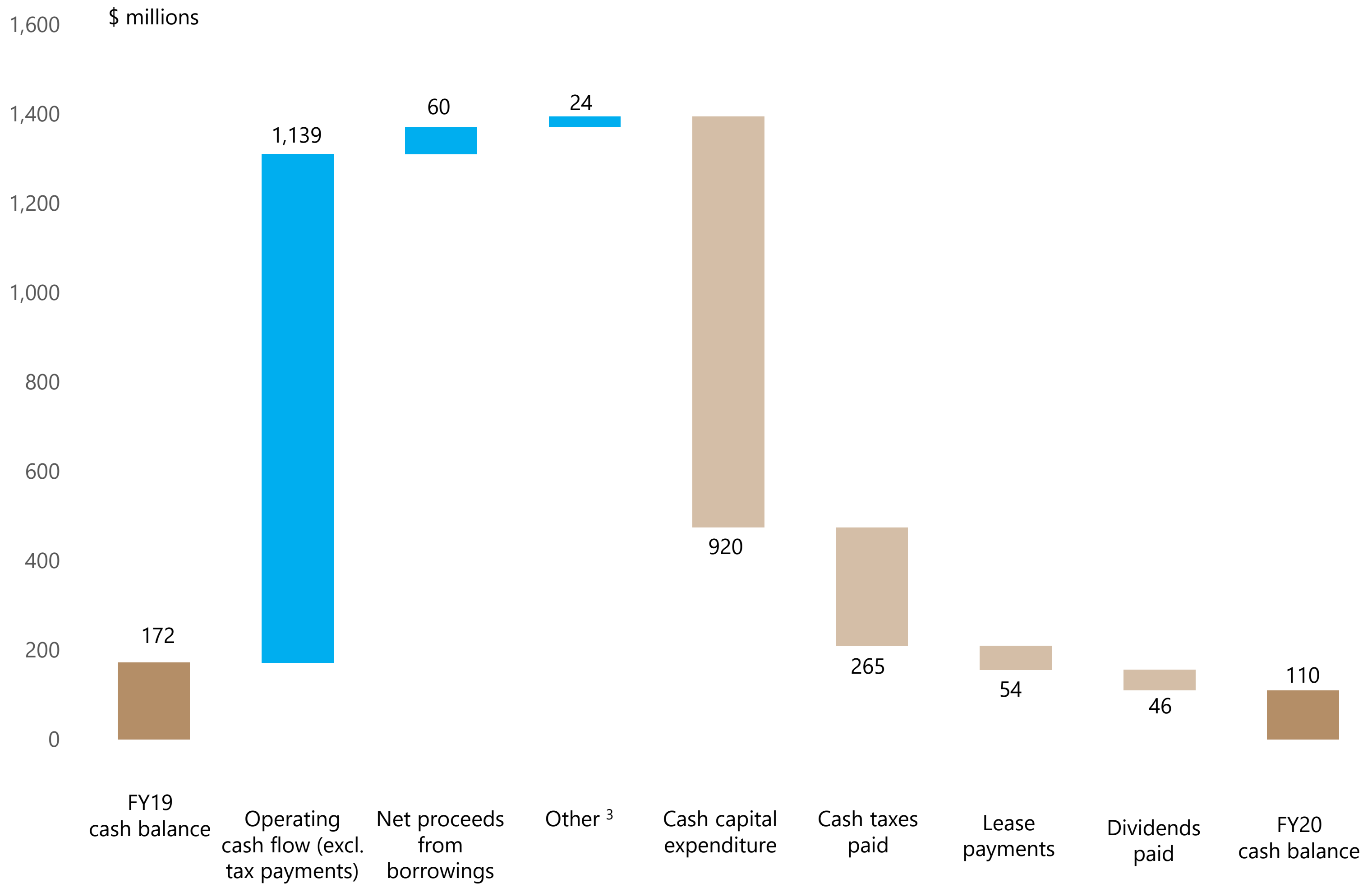
1. In FY19 Beach accounted for its Victorian Otway interests at 100% interest until 31 May 2019 and 60% thereafter. For comparison purposes with prior periods, pro forma production shows production based on 60% ownership of Victorian Otway for the entire comparison period.
2. Underlying results in this presentation are categorised as non-IFRS financial information provided to assist readers to better understand the financial performance of the underlying operating business. They have not been subject to audit or review by Beach's external auditors. The information has been extracted from the audited financial statements. For a reconciliation of FY20 net profit after tax to underlying net profit after tax, refer to Appendix.

Financial strength maintained

Strong operating cash flow supports record investment program

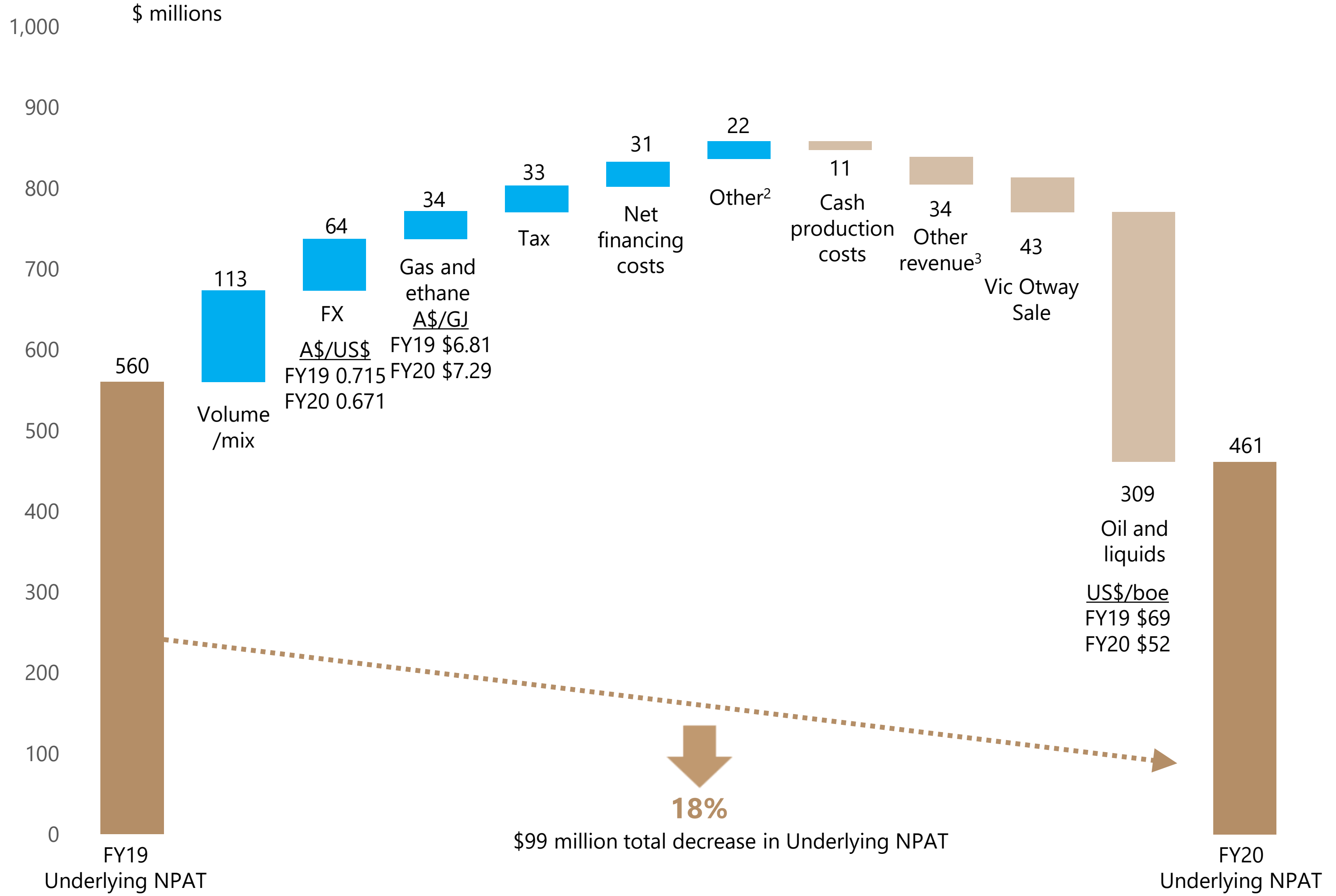
- FY20 operating cash flow, excluding tax paid, of $1,139 million
- FY20 cash tax of $265 million
- Record cash capital expenditure of $920 million as multi-year capital investment campaign ramps up[1]
- Closing cash balance of $110 million:
  - Net cash position of $50 million[2]
  - Total liquidity of $500 million (cash plus revolver availability) at 30 June 2020
- No net cash impact from application of AASB 16 accounting standards (refer appendices)

Movement in cash



1. FY20 cash capital expenditure is higher than $863 million due to working capital movements and cash pre-payments
2. Net cash defined as drawn debt less cash and cash equivalent.
3. Other includes proceeds from government grants, net proceeds from divestments, proceeds from repayment of employee share loans, payment for shares purchased on-market (employee share plan) and effect of exchange rate on foreign cash balances.

Movement in Underlying NPAT



$461 million Underlying NPAT is 18% lower than FY19 driven by factors including:

- 24% reduction in realised USD liquids prices
- Sale of 40% interest in Victorian Otway assets
- $34 million reduction in other revenue

Partly offset by impact from:

- $113 million contribution from higher liquids volumes
- $64 million from lower AUD
- Higher realised Australian dollar gas prices

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2. Other includes $46 million third party purchases, $11 million in inventory movements and $5 million other expenses, less $39 million in third party sales and $1 million in depreciation
3. Other revenue includes the unwinding of liabilities associated with gas sales agreements

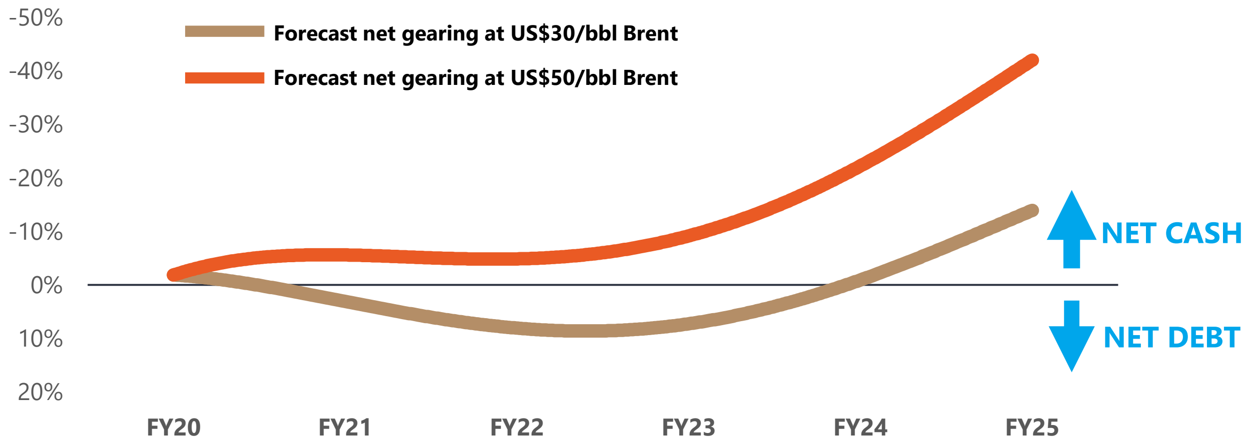
Balance sheet and capital management

Rock solid balance sheet and gas revenues support growth

Balance sheet strength

- $50 million net cash, $500 million liquidity at 30 June 2020
- Fixed price gas contracts provide revenue certainty, cover all operating costs
- Current projections have Beach remaining in net cash position through peak investment year at ~US$40/bbl Brent

5 year outlook forecast net gearing[1]



Capital management framework

Beach's capital management priorities remain unchanged:

- Beach remains a growth oriented company
- Substantial portfolio of highly value-accretive organic growth opportunities
- Beach to remain selective and disciplined in relation to M&A opportunities
- Conservative approach to balance sheet management.
- Free cash flow generation prioritised towards growth reinvestment, but will consider capital returns for surplus capital

Net gearing forecast to remain below 10% at US$30/bbl oil through 5 year outlook while fully funding all identified growth projects

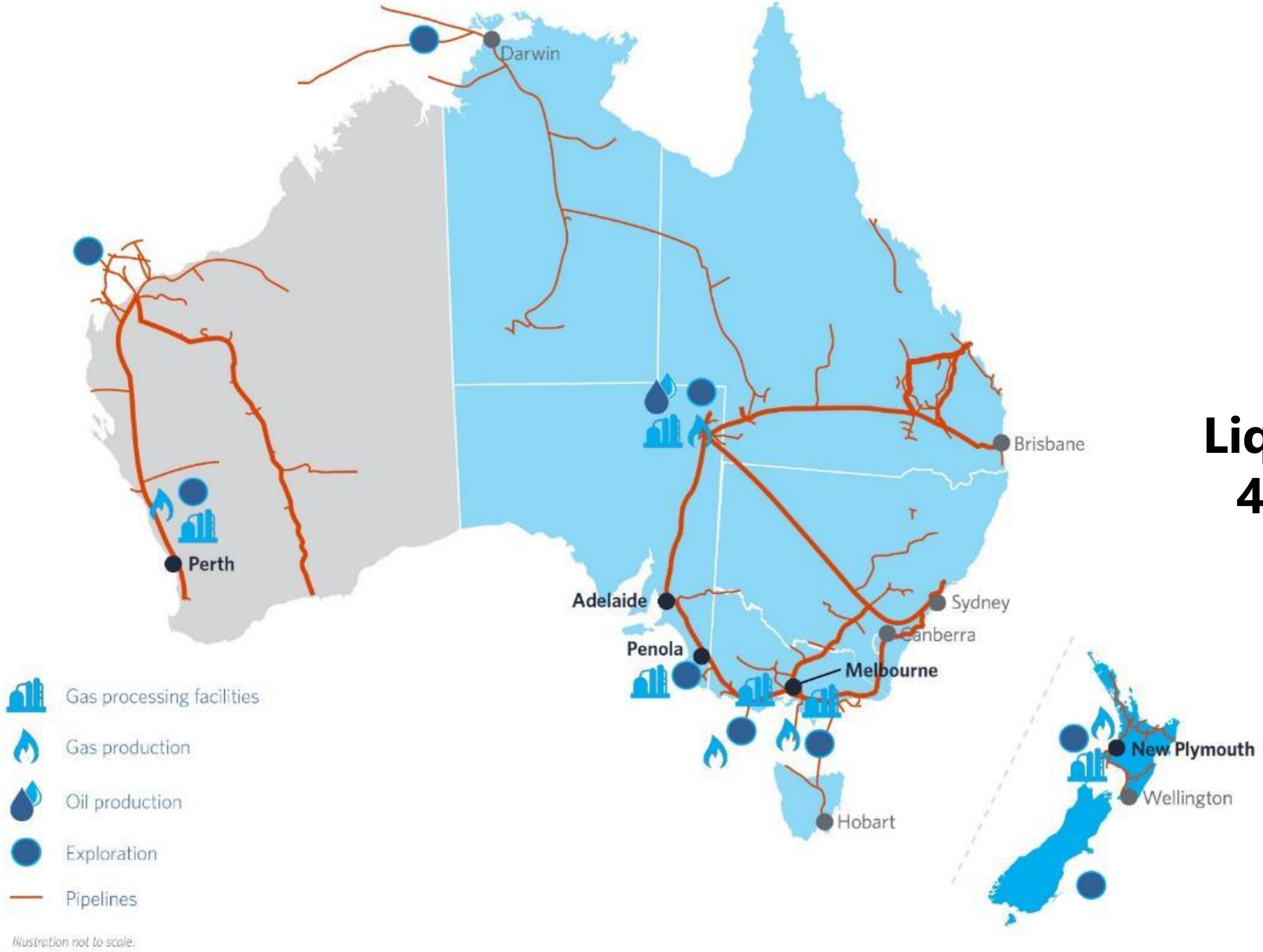
1. Refer to disclaimers and assumptions on slide 2. AUD/USD = 0.70 through 5 year outlook. Forecast net gearing calculated as net debt divided by net debt plus equity. Excludes the impact of future dividends or other capital management initiatives.

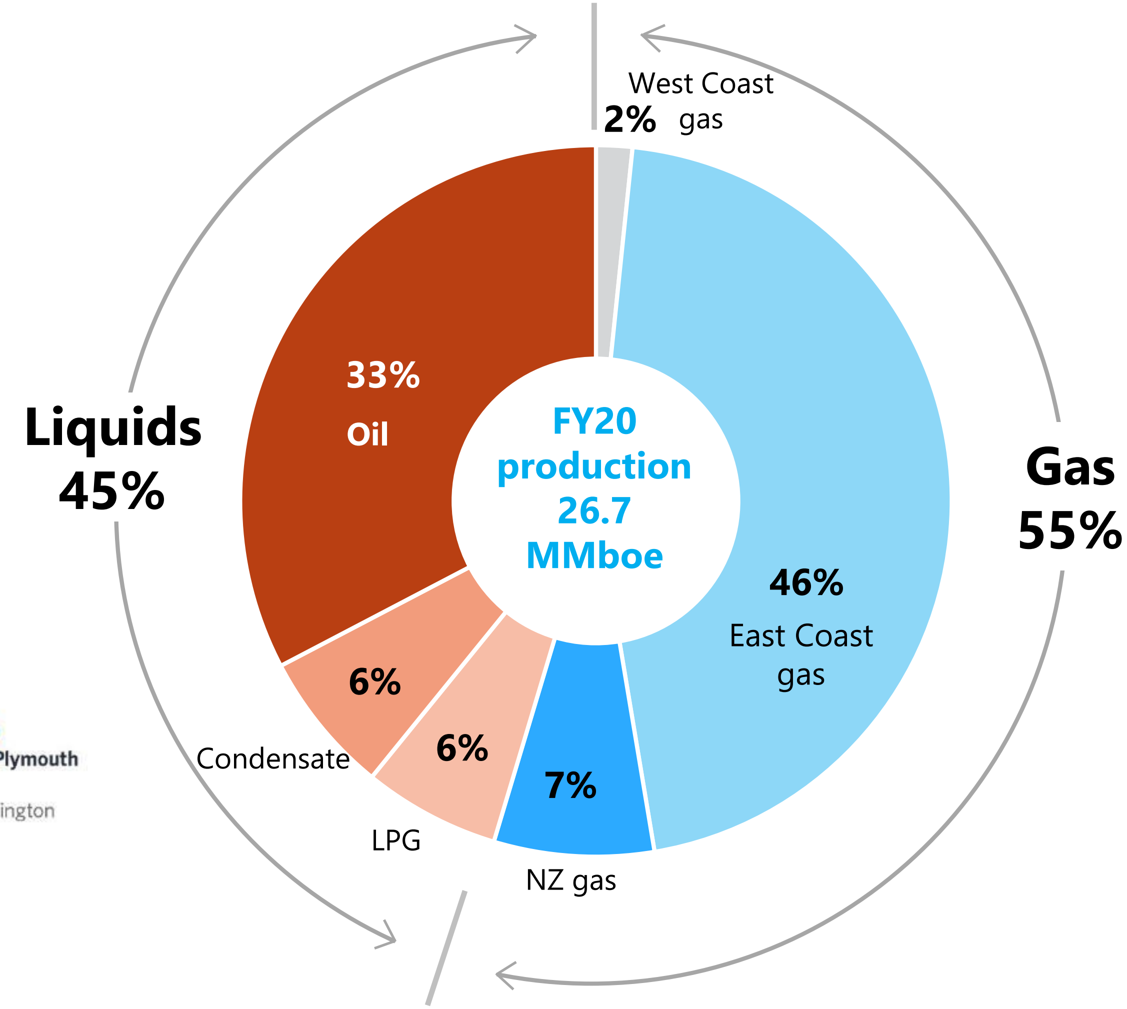
FY20 FULL YEAR RESULTS AND OUTLOOK PRESENTATION

Our markets

Beach Energy portfolio diversity

Six production hubs supplying 3 distinct gas markets

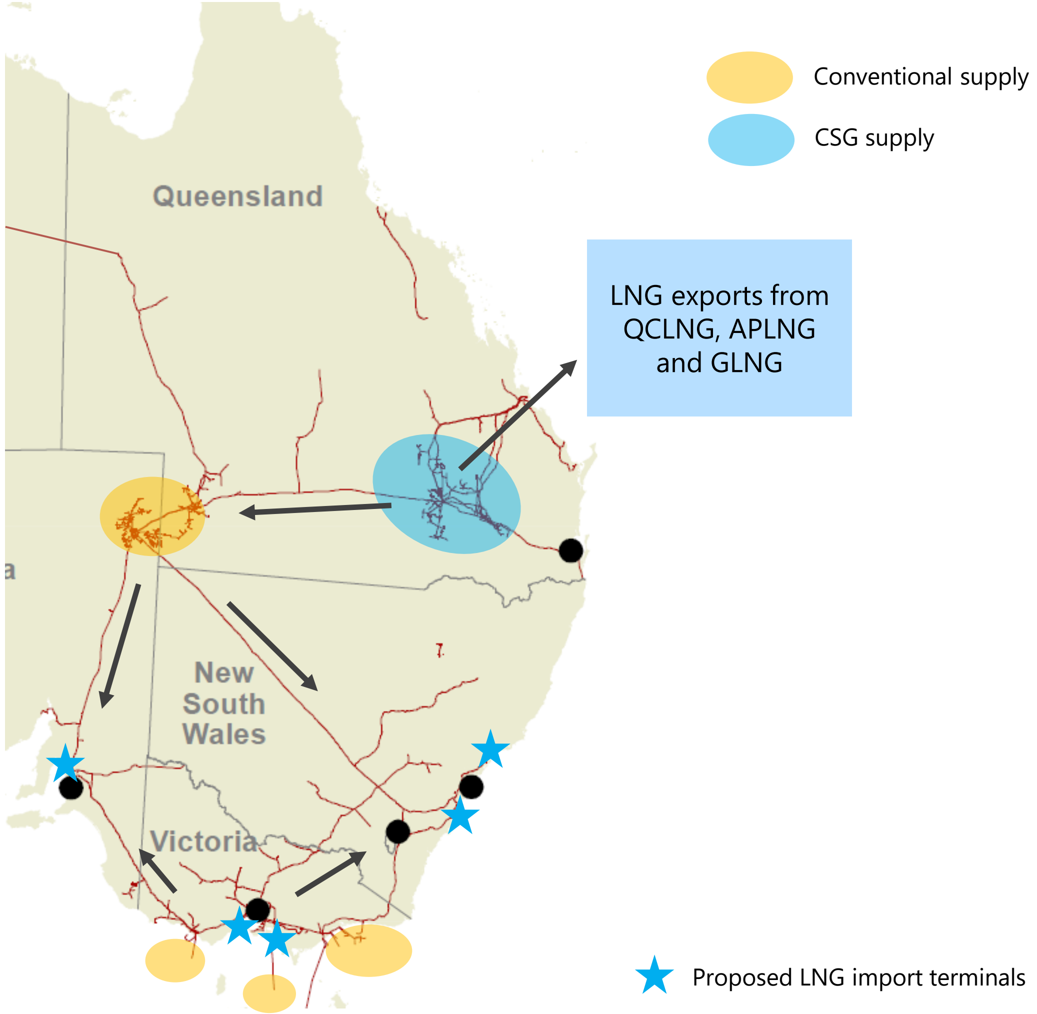




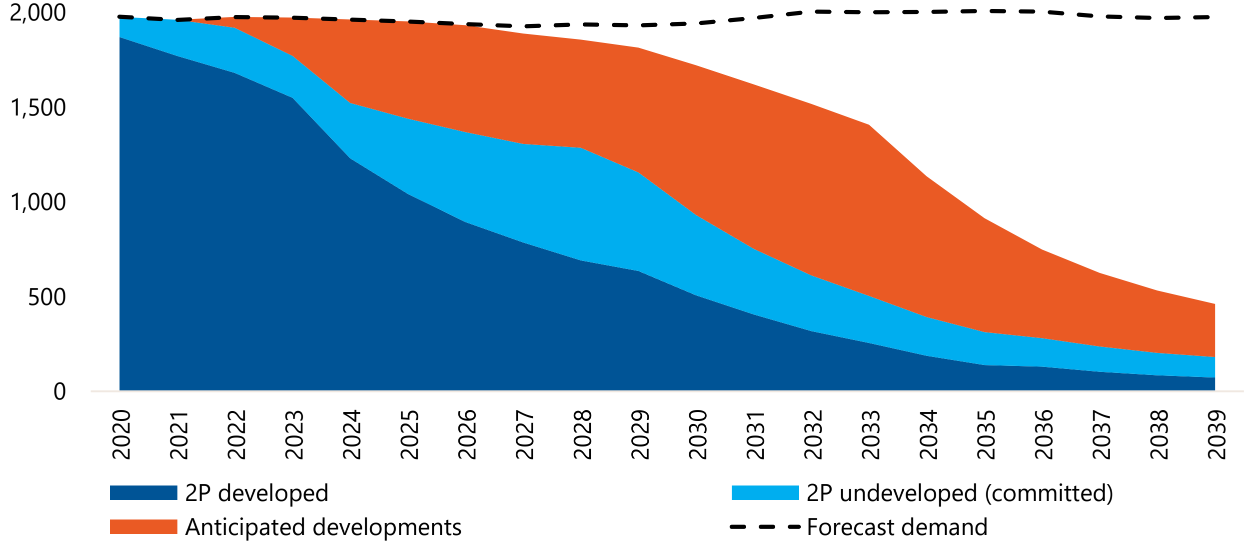
Portfolio diversity (location, product, gas market) provides natural hedge

East coast gas market

Market dynamics support Beach's investment strategy



Eastern Australia gas demand vs supply (PJ)[1]



- AEMO forecasts Eastern Australian gas production insufficient to meet demand
- Supply shortfall has been met from Queensland, primarily gas diverted from LNG
- AEMO forecasts demand/supply gap to widen, increasing reliance on LNG
- AEMO highlights timing risk of anticipated developments

Beach view

- Short term contract price pressure in FY21 from QLD LNG diversions
- Medium to long term price outlook strong

1. Source: AEMO Gas Statement of Opportunities 2020.

Beach portfolio not exposed to east coast spot gas prices

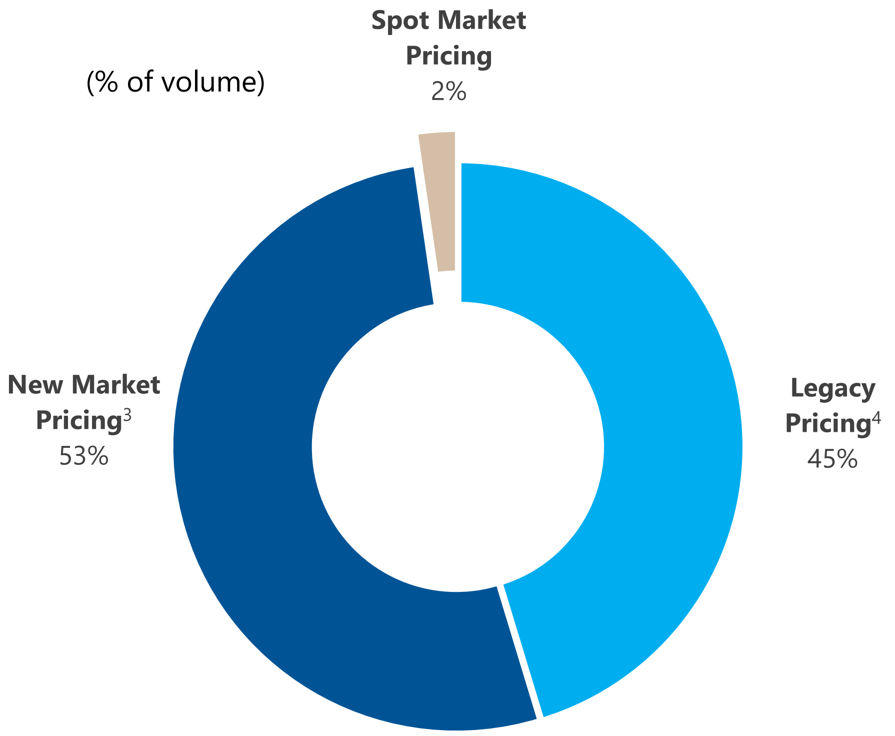
Recent gas market dynamics

- Low LNG spot prices have resulted in increased diversion of LNG gas supplies into the East Coast gas market, impacting spot prices
- **Beach has minimal spot gas price exposure:** More than 97% of East Coast gas sales expected to be sold under contract in FY21 and FY22
- Origin GSA gas price review underway, result to be back-dated to 1 July 2020

Mid-long term gas market dynamics

- Non-CSG East Coast gas supply is expected to decline in the medium-term in the absence of material new developments[1]
- There are physical (pipeline) constraints on how much QLD gas can flow to southern demand centres, no matter how much is made available long-term
- LNG imports to the East Coast would require domestic prices of >$9/GJ if long-term LNG prices were as low as US$6/MMBtu[2]

Forecast FY21/22 East Coast Gas Sales

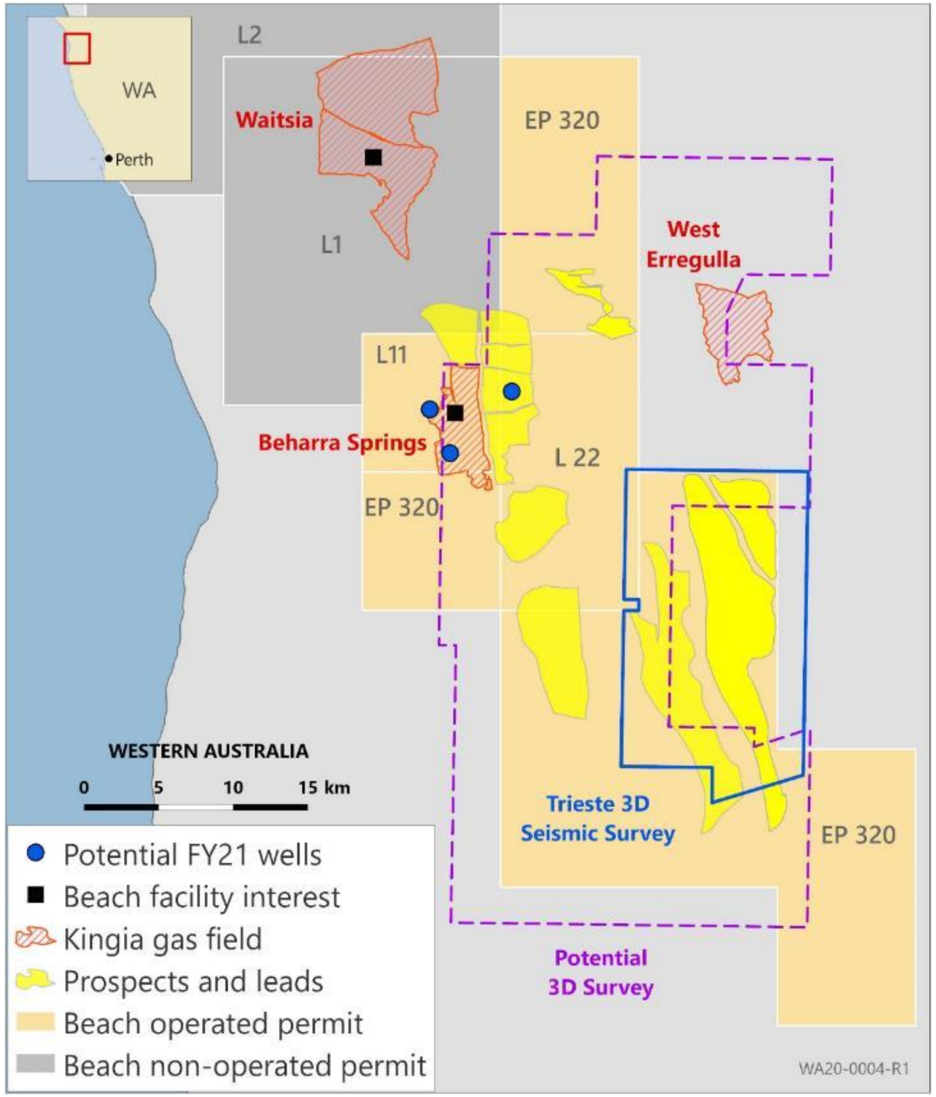


> 97% of Beach's east coast gas sales in FY21 and FY22 expected to be sold under term contracts

1. Source: 2019 Gas Statement of Opportunities, AEMO – March 2019.
2. Beach estimates: 1 MMBtu = 1.055 GJ, AUD/USD = 0.70, regasification of A$1.00/GJ.
3. New market pricing refers to gas contracted from FY19 onwards at prices reflective of analogous contracted east coast gas volumes.
4. Legacy pricing refers to gas contracted prior to FY19 at prices not reflective of analogous contracted east coast gas volumes since FY19.

FY20 FULL YEAR RESULTS AND OUTLOOK PRESENTATION

Asset update



In FY21 the Waitsia and Beharra Springs JVs will supply up to 40 TJ/day into the WA gas market

Perth Basin

Final Investment Decision planned for Waitsia Stage 2 in December quarter

FY20 outcomes

- Aligned Perth Basin interests with Mitsui (MEPAU)
- FID of Waitsia Stage 1 expansion (to 20 TJ/day)
- Success at Beharra Springs Deep 1 exploration well, flowing at up to 46 MMscfd on test
- Initial booking of 29 MMboe 2P reserves in Beharra Springs Deep
- Trieste 3D seismic survey under evaluation to confirm exploration well locations in EP 320
- Two GSAs with Alinta, one with Waitsia (up to 20 TJ/d over 4.5 years), the other with Beharra Springs (supported by Beharra Springs Deep 1)

Proposed FY21 activities

- Waitsia Stage 1 expansion commissioning underway. Introduction of first gas imminent
- Target FID of Waitsia Stage 2 planned in Dec' 20 quarter based on 250 TJ/d development
- Tie-back of Beharra Springs Deep 1 to existing Beharra Springs gas facility planned for Q3 FY21

Strategic considerations

- Large, high quality, low cost gas resource close to existing major gas pipelines
- Early mover advantage in 2019/20 negotiating LNG exports via North West Shelf
- WA domestic market well supplied through early 2020s, then tighten as existing supplies decline
- Beach also targeting further domestic market opportunities
- Robust exploration and appraisal portfolio provides low risk, high upside potential

Economic considerations

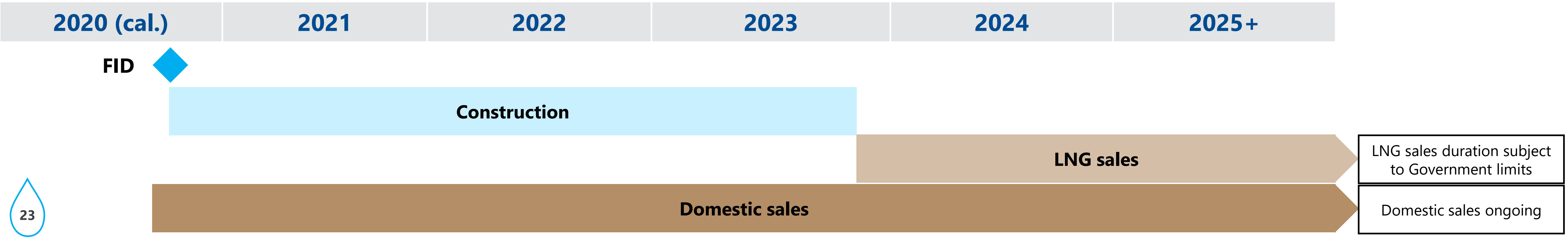
- Prolific Kingia formation deliverability. Only six conventional development wells initially required to supply 250 TJ/day Waitsia Stage 2 facility
- Low liquids, low gas inerts reduces processing development and operating costs
- Potential for gas processing capacity expansion confirmed at existing Beharra Springs facility

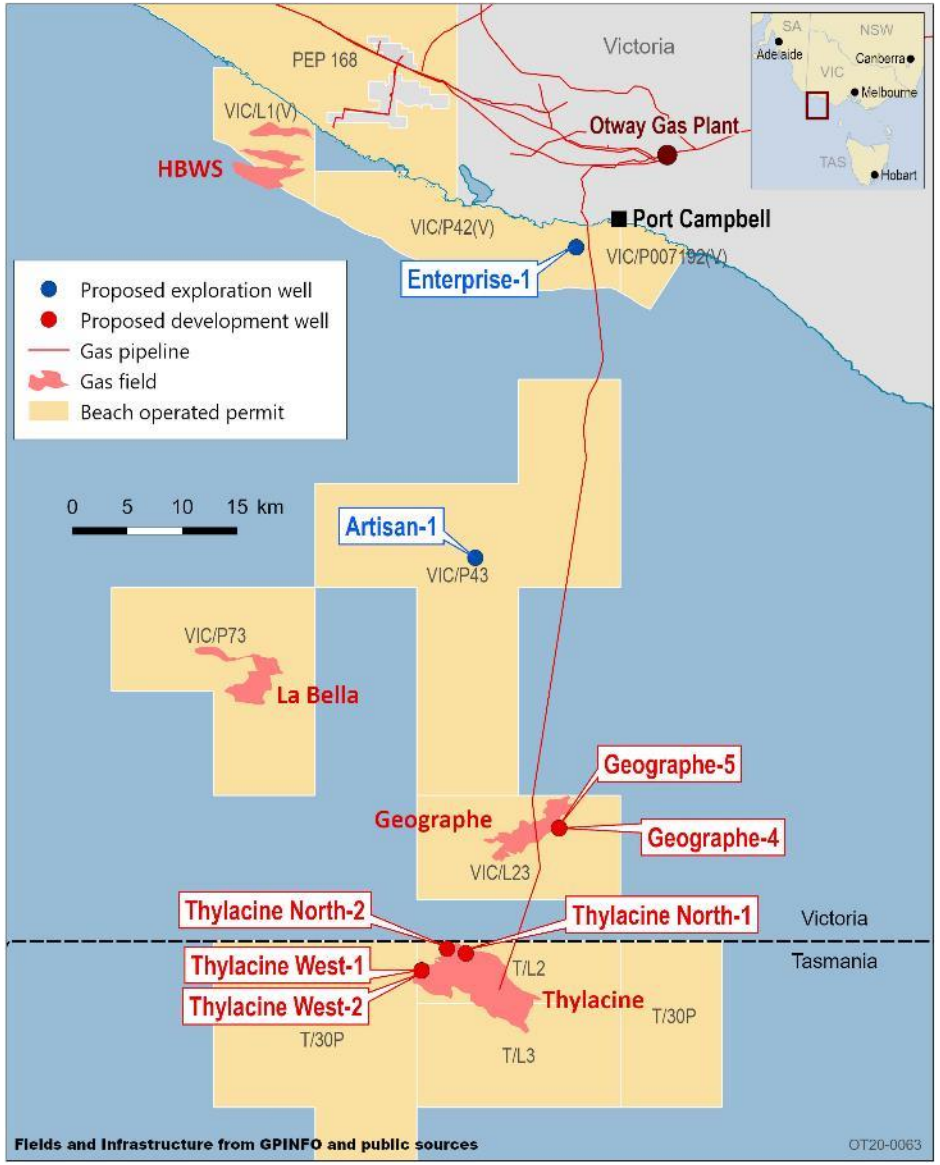
Waitsia Stage 2 expansion via North West Shelf (NWS)

Two years of progress and ready to reach Final Investment Decision

North West Shelf access	✓ Non-binding gas processing term sheet signed with NWS ✓ Fully termed agreements being worked through ✓ Plan to sell equity LNG from start-up in late calendar 2023 ✓ LNG marketing to occur through FY21 and FY22
Pipeline access	✓ Large diameter (280 TJ/d) connection to AGIG owned DBNGP in place ✓ Transportation arrangements with AGIG being finalised
Government and regulatory approvals	✓ Finalising arrangements with the WA government to support both the Waitsia domestic gas commitment and export of ~50% of project 2P reserves through the NWS Facilities ✓ Environmental approvals on track
Final design and costings	✓ Final EPC bid for 250 TJ/d gas processing facility due in September 2020 ✓ Sufficient capacity to generate ~1.5 million tonnes per annum of LNG
Funding	✓ Beach share of construction costs to be funded from operating cash flow

Final Investment Decision in December Quarter





Victorian Otway Basin

Offshore drilling campaign to commence in FY21

FY20 progress and current status

- Executed new rig contract at competitive day rate with Diamond Offshore
- 6 firm and 3 option wells with Ocean Onyx
- Focus is to refill the 205 TJ/d Otway Gas Plant
- Black Watch 1 – longest onshore well in Australia, connected in late May 2020, delivering 45 TJ/d

Forward plan

- 23 day Otway Gas Plant statutory shutdown currently planned for November 2020
- Offshore drilling to commence Dec '20- Mar '21
- Artisan 1 exploration first well in program
- Drilling delay mitigated supply chain risks
- Enterprise 1 exploration well expected to spud in Q2 FY21, subject to mitigating COVID-19 risks
- Contribution from new wells expected in FY22-24

Strategic considerations

- Key gas infrastructure supplying domestic customers in the East Coast gas market
- Long term gas contracts in place for existing 2P reserves (excluding La Bella)
- Opportunity to market incremental volumes from exploration success to new customers

Economic considerations

- Well IRRs range from 30 – 75%
- Payback time for most wells < 2 years
- Economic field life FY36

Victorian Otway Basin

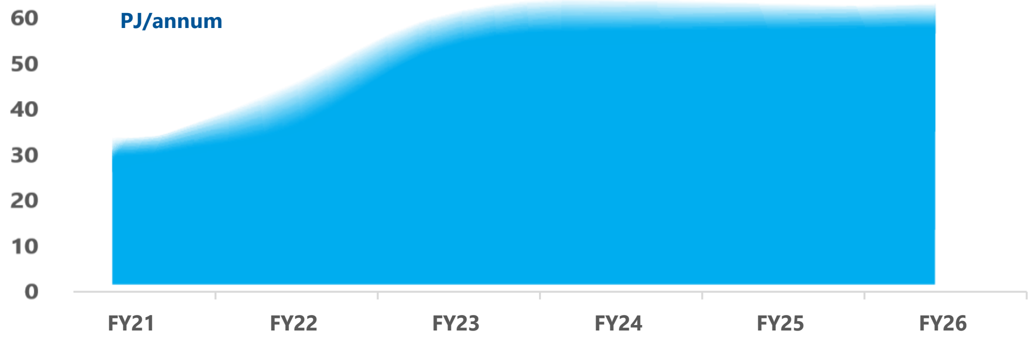
Mitigating COVID-19 related supply chain and execution risks

Supply chain location for Offshore Victorian Otway Basin drilling and development campaign

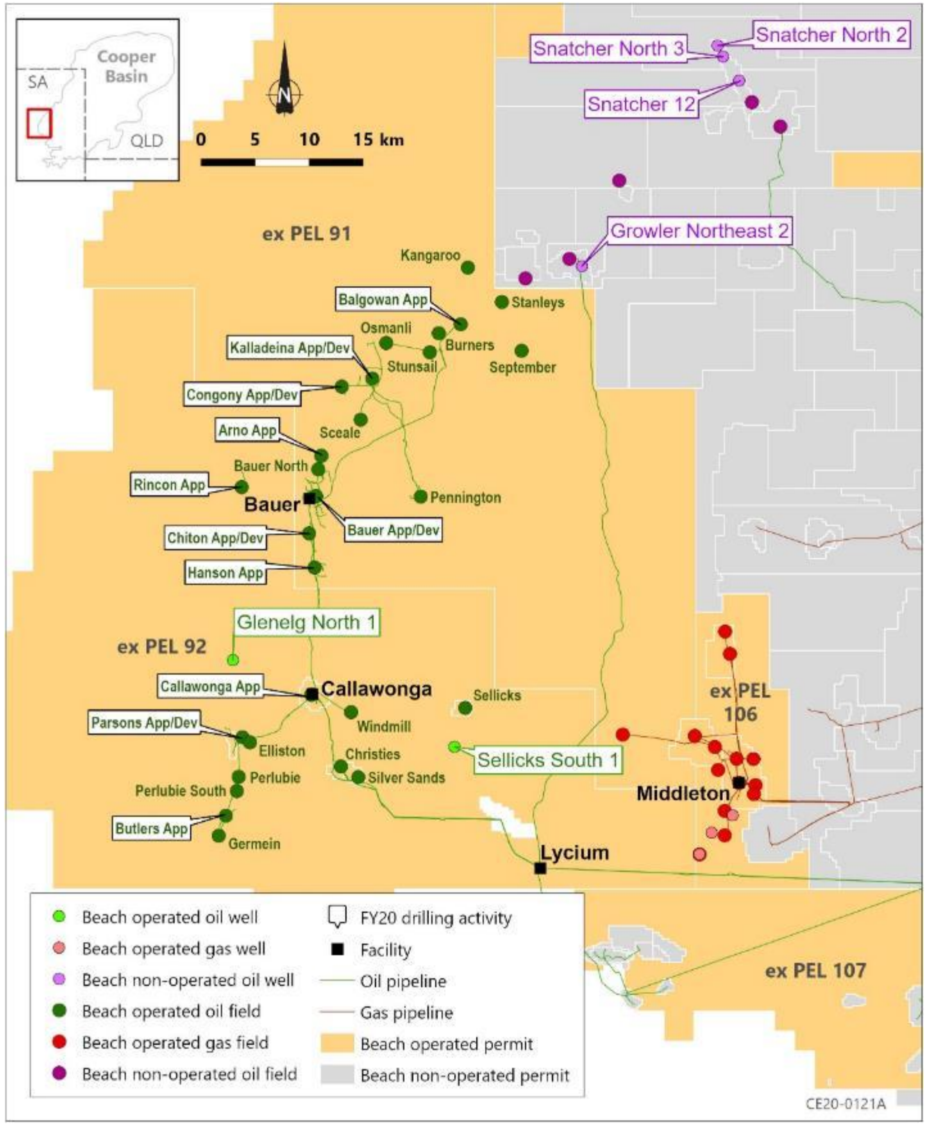
Examples of COVID-19 supply chain interruptions and mitigation actions

Item	Location	COVID-19 Challenges	Mitigation
Xmas Trees	Batam, Indonesia	Skilled personnel unable to travel in and out of Batam	Final stage of construction moved to Perth, Australia
Subsea Control Modules	Batam, Indonesia	Skilled personnel unable to travel in and out of Batam	Final stage of construction moved to Perth, Australia
Vertical Control Systems	Victoria, Australia	Specialist personnel were unable to travel to Victoria	Works relocated to Port Klang, Malaysia
Pipes & Bends	Italy and Holland	Transport delays due to airport closures	Rerouted via Singapore, Kuala Lumpur, Milan and Luxembourg

Otway Gas Plant forecast gross gas output



Less than 5% of Victorian Otway present value reduction through delayed drilling program



Western Flank Oil

159% 2P reserves replacement
Wells generating IRRs >100%

FY20 progress

- Outstanding drilling results in FY20
- 75 wells drilled, including 26 horizontal wells
- Operated production increased to as high as 23,000 BOPD in H2 FY20
- Drilling success added 11.5 MMboe in 2P reserves, a 159% 2P reserves replacement ratio

Proposed FY21 activities

- Target maintaining gross average output above 20,000 BOPD in FY21
- FY21 capex ~$110 million, 50% lower than FY20 due to reduced drilling activity
- Further appraisal opportunities identified. At least 4 oil fields yet to be fully appraised
- High grade prospect and lead portfolio for drilling program in FY22 and beyond

Strategic considerations

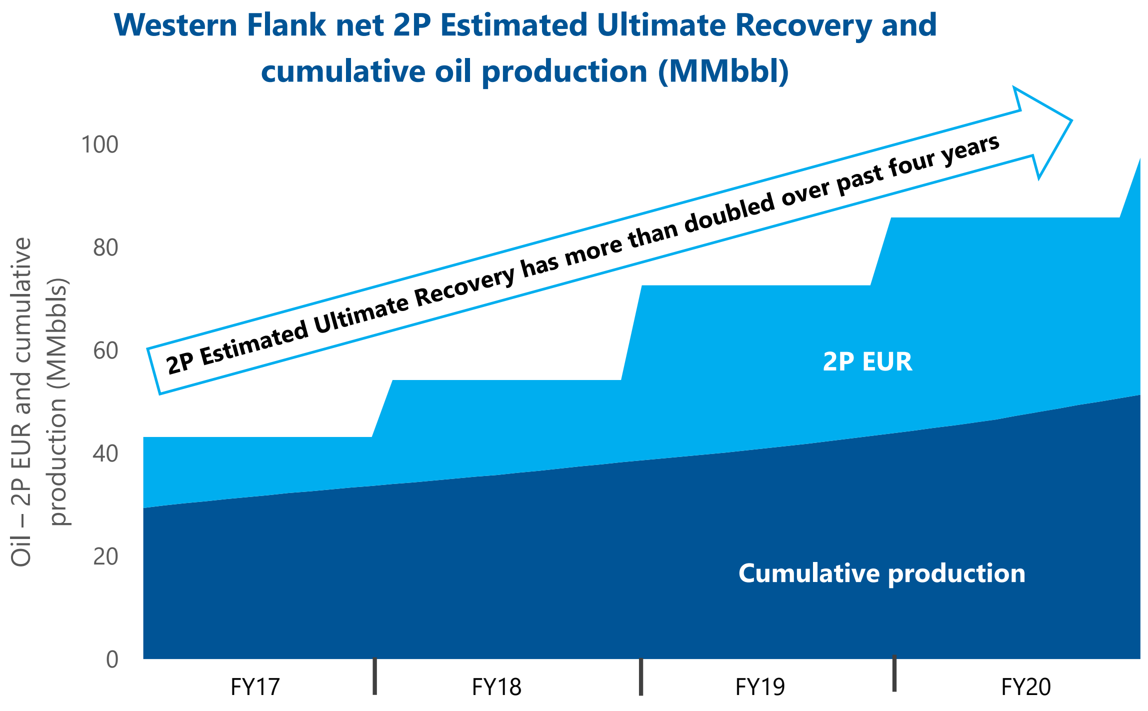
- High returning asset with significant exploration, appraisal and development potential
- Operatorship and majority owner – can control pace and focus of work program

Economic considerations

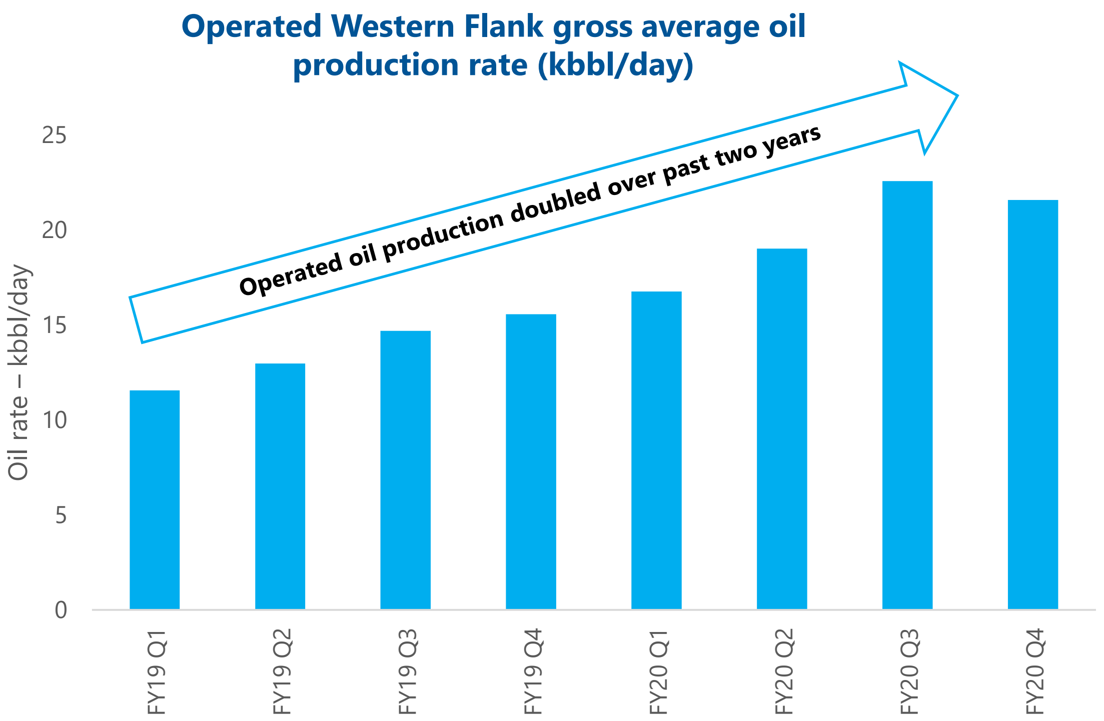
- Most development well IRRs >100%
- Payback time avg 6 months at lower oil prices
- Field operating cost remains below $5/boe
- Horizontal drilling has seen a ~8x increase in productivity at 1.5x cost of vertical wells
- Crude historically sold at premium to Brent

Western Flank Oil

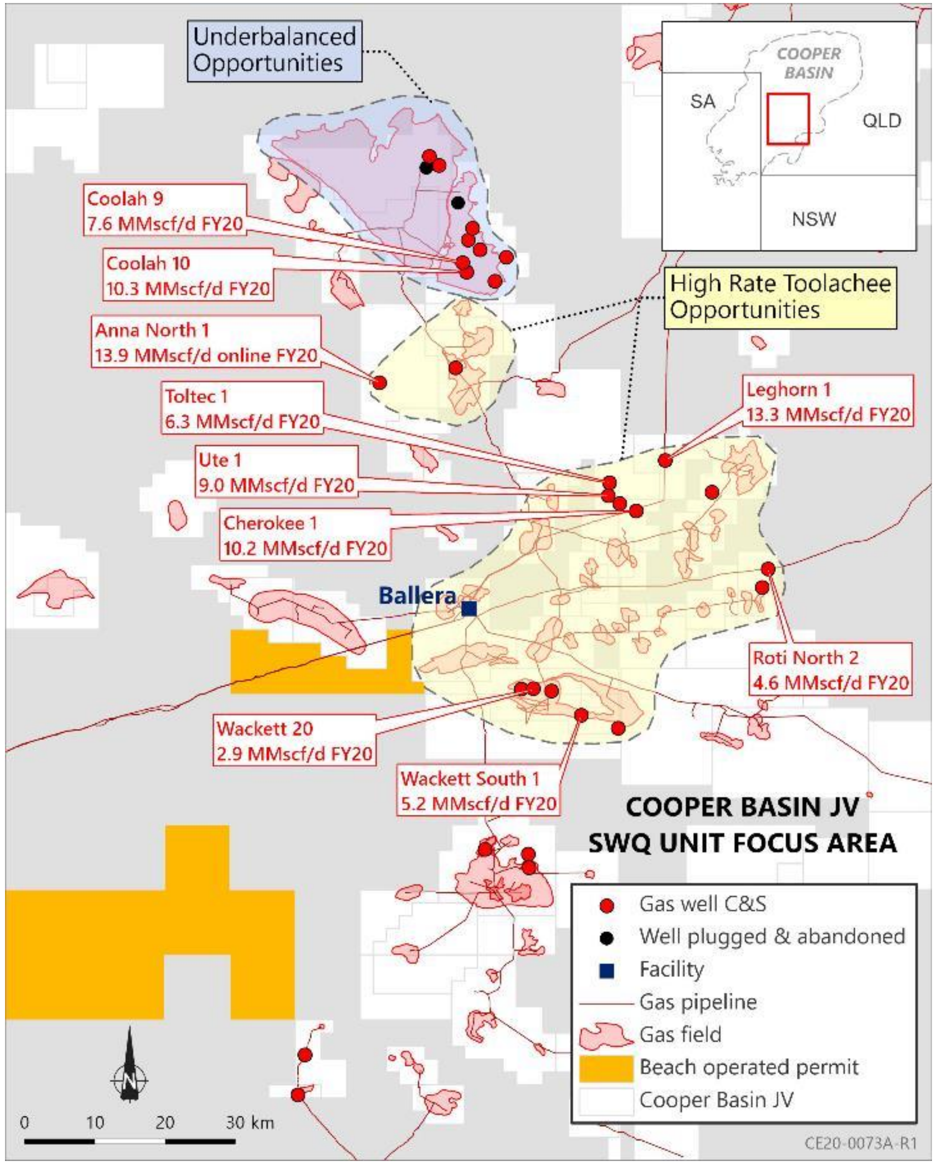
Estimated Ultimate Recovery has more than doubled over past 4 years, production has doubled over past 2 years



- ✓ Appraisal subsurface workflow ('Bauer approach') implemented across the Western Flank defining field limits and increasing field Estimated Ultimate Recovery (EUR)
- ✓ Production and EUR have more than doubled in the past 5 years
- ✓ 2P EUR approaching 100 MMbbl (net to Beach)



- ✓ Development of the McKinlay reservoir in Bauer, Chiton, Congony and Kalladeina has reinvigorated oil production on the Western Flank
- ✓ Horizontal well design with simple slotted liner and swellable packers
- ✓ Drill times have improved by >30%
- ✓ Downhole pumps optimised for well productivity



Cooper Basin JV

Focus on participating in high quality drilling campaign in FY21

FY20 outcomes

- FY20 production of 8.7 MMboe was 6% higher than prior year
- 111% 2P reserves replacement ratio in FY20
- Successful gas drilling campaign in SWQ Unit:
  - High rate potential demonstrated across 8 wells
  - 30 day average IP rate of 3-14 MMscf/d

Potential FY21 activities

- Highly supportive of operator Santos high grading drilling opportunities in FY21
- Beach expects to participate in 40-50 wells
- Focus on infrastructure opportunities to support improved production reliability and capacity
- Carbon Capture and Storage (CCS) potential to be evaluated in H1 FY21

Strategic considerations

- CBJV covers more than 16,000 km^2
- Despite asset maturity, upside exploration opportunities continue to yield positive results (e.g. FY20 SWQ Unit drilling results)
- Infrastructure includes gas processing and storage as well as liquids processing, transport, storage and sales
- Connected to 3 major east coast gas pipelines
- Depleted reservoirs have CCS and gas storage potential

Economic considerations

- Well IRRs can range from 10% to >50%
- Maximise return in a low price environment
- Disciplined capital management
- Focus on gas with stable price

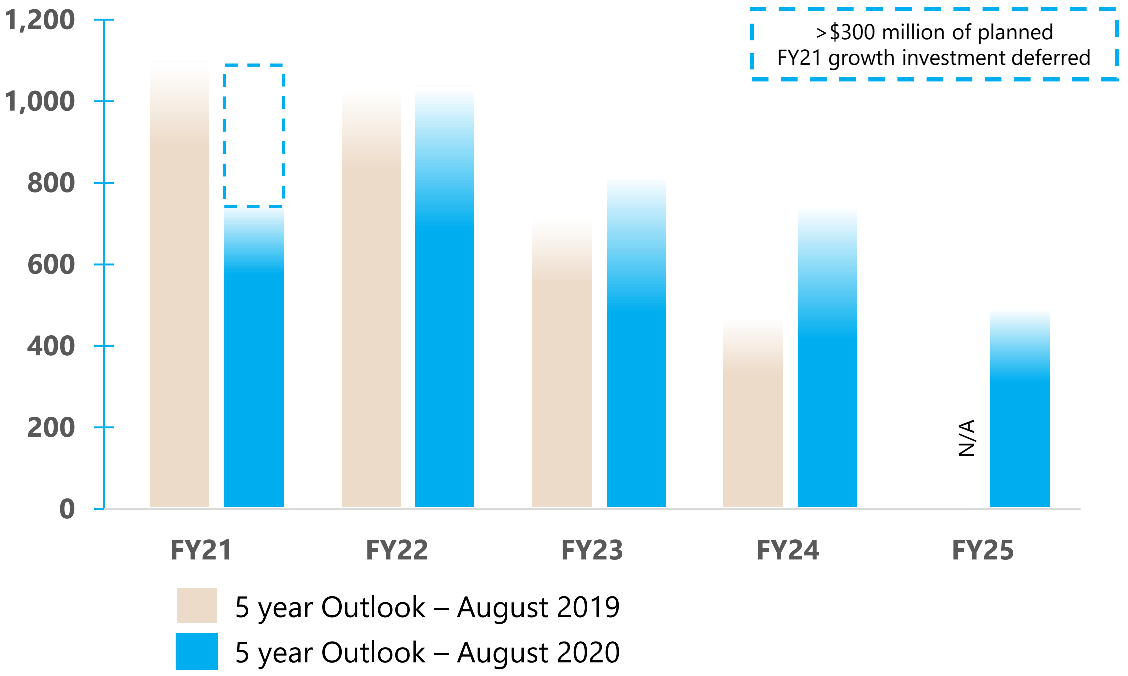
Updated 5 year outlook

5 year investment expenditure outlook

Prudent deferral of FY21 investment to manage external challenges

5 Year Capital Expenditure Outlook[1]

($ million)



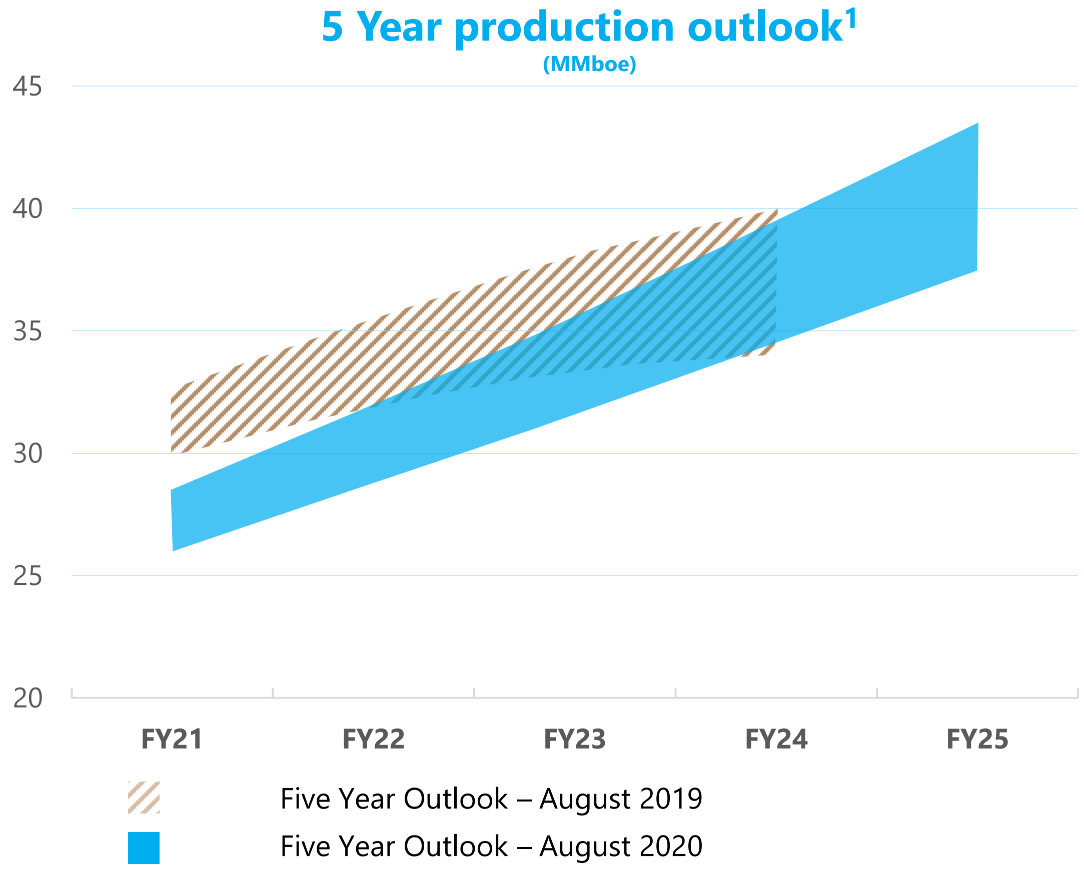
More than 30% of planned FY21 expenditure deferred

- **FY21 was on track to be Beach's biggest investment year**
  - Full year of offshore Victorian Otway program
  - Full year of Waitsia Stage 2 construction
  - Continued aggressive Cooper Basin drilling program
- **Planned FY21 capex reduced by >30% to $650-750 million**
- **FY20-24 cumulative capex has increased by ~$200 million to $4.2 billion as new growth opportunities are identified**
  - ✓ Follow up drilling/development in Perth Basin following exploration success at Beharra Springs Deep[2]
  - ✓ Increased Western Flank investment following FY20 success
  - ✓ Kupe JV considering new well to extend plateau beyond FY24

1. Outlook is determined using the assumptions set out on the "Compliance Statements" slide.
2. As outlined in FY20 half year results presentation in February 2020.

5 year production outlook

Production on track to deliver 37-43 MMboe in FY25



Investment deferral shifts production growth outlook

- **Production growth impacted by FY21 investment expenditure deferral and COVID-19**
  - ✓ Offshore Victorian Otway wells now expected to commence production in FY22-23 (Prior: FY21-22)
  - ✓ Deferred FY21 activities surrounding Western Flank Gas expansion, Trefoil development and SA Otway expansion will delay potential production contribution from these assets
- **Waitsia Stage 2 start-up now forecast by end calendar 2023** (prior: mid calendar 2023)
- **Cumulative production deferral from FY20-24 relative to August 2019 5 year outlook primarily relate to:**
  - Victorian Otway Program deferral
  - Waitsia Stage 2 start-up deferral

1. Outlook is determined using the assumptions set out on the "Compliance Statements" slide.

Low risk delivery of 37 MMboe by FY25, with upside

Growth portfolio has optionality

To deliver	Key assumptions	Requirements
37 MMboe in FY25	▪ Stable gas production from Cooper Basin JV ▪ 33% exploration/appraisal Western Flank success rate ▪ Re-filling 205 TJ/day Otway Gas Plant by end FY23 ▪ Waitsia Stage 2 FID H1 FY21, start-up by end calendar '23 ▪ Western Flank gas expansion	▪ ~50 development wells/year in CBJV ▪ High grading Western Flank exploration ▪ Executing offshore development program ▪ Finalise Waitsia commercial negotiations ▪ Low risk Western Flank gas exploration
Above 37 MMboe	▪ >33% exploration/appraisal success in Western Flank oil ▪ Beharra Springs gas expansion ▪ Bass Basin development (Trefoil) ▪ More than 1 exploration success in Victorian Otway Basin ▪ SA Otway gas expansion ▪ Ironbark and Wherry (longer term growth potential)	▪ Sustaining high Western Flank oil success rate ▪ Beharra Springs appraisal success ▪ Trefoil concept select, FEED and FID ▪ Success in Victorian Otway exploration program ▪ Further SA Otway appraisal success ▪ Successful frontier exploration success

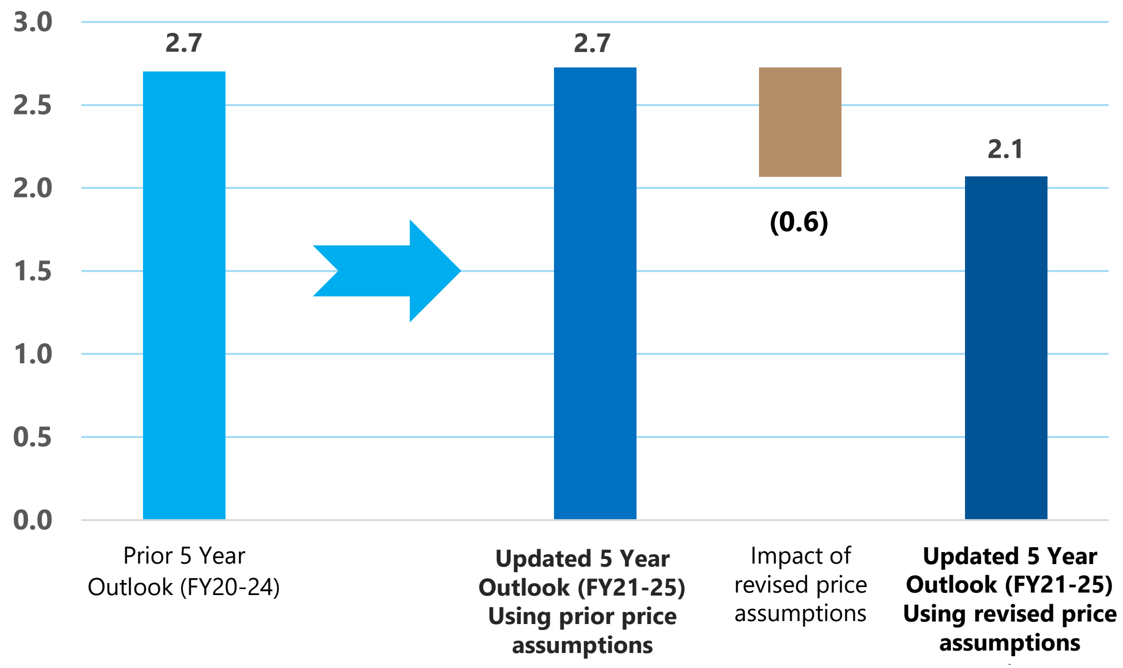
Multiple options for continued growth

5 year free cash flow outlook

Revised investment profile, commodity price outlook set to deliver $2.1 billion in FCF

5 Year free cash flow outlook[1]

($ billion)



FCF outlook updated for revised timing, price assumptions

- **$2.1 billion in cumulative free cash flow forecast from FY21-25**
- **New FCF outlook reflects:**
  - ✓ Updated project timing, capital and operating cost and tax estimates
  - ✓ Forecast Brent oil price of US$41.25/bbl in FY21, US$52.50/bbl in FY22 and US$60/bbl from FY23 (AUD/USD of 0.70)
  - ✓ Applying the same commodity price assumptions as prior year would generate $2.7 billion FCF from FY21-25
- **Prior 5 year outlook** from FY20-24 was based on Brent oil price of US$62.50/bbl in FY20 and US$70/bbl thereafter (AUD/USD of 0.70 in FY20 and 0.75 from FY21-24)

1. Outlook is determined using the assumptions set out on the "Compliance Statements" slide . Free cash flow is defined in disclosures on slide 2 of this presentation. For five year outlook purposes cash flows associated with operating leases are not adjusted for potential changes from AASB 16.

FY21 guidance

FY21 guidance

	FY20 actual	FY21 guidance
Production	26.7 MMboe	26.0 - 28.5 MMboe
Capital expenditure[1]	$863 million	$650 - 750 million
Underlying EBITDA	$1,108 million	$900 - 1,000 million
DD&A[2]	$16.8/boe	$17.5 - 18.0/boe
Field operating costs/boe	$9.0/boe	$8.25 - 8.75/boe

1. Excludes corporate capital expenditure.
2. Excludes DD&A associated with corporate assets.

Notes

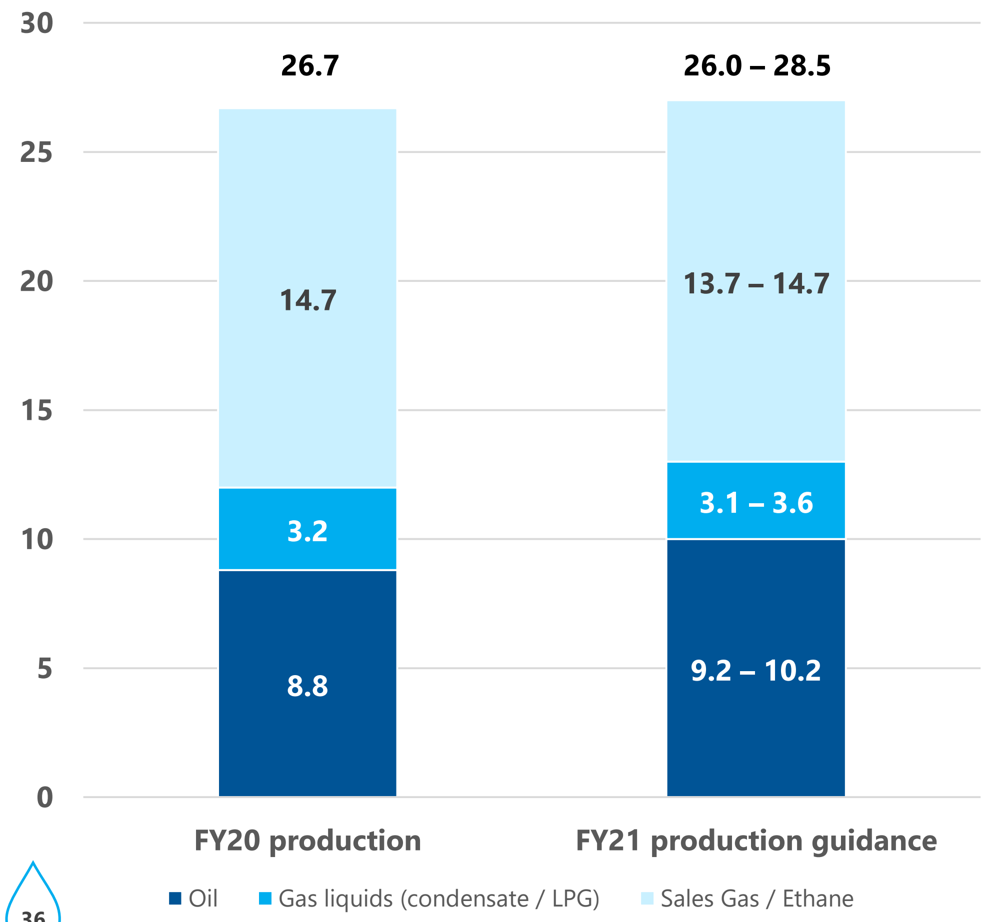
- Underlying EBITDA guidance excludes any potential impact from Ironbark and Wherry costs (subject to drilling results)
- Underlying EBITDA guidance includes $23 million "other income" associated with the unwinding of GSA assets and liabilities (non-cash)
- FY21 DD&A guidance includes ~$0.60/boe associated with the impact of AASB 16 (lease) accounting standard
- No PRRT expected to be paid in FY21

Production maintained in a lower capital environment

FY21 production guidance

COVID-19 risks have increased potential range of uncertainty

FY21 production guidance split vs FY20 actual



Oil production

- Forecast increase by maintaining Western Flank output above 20,000 BOPD through FY21 (average)

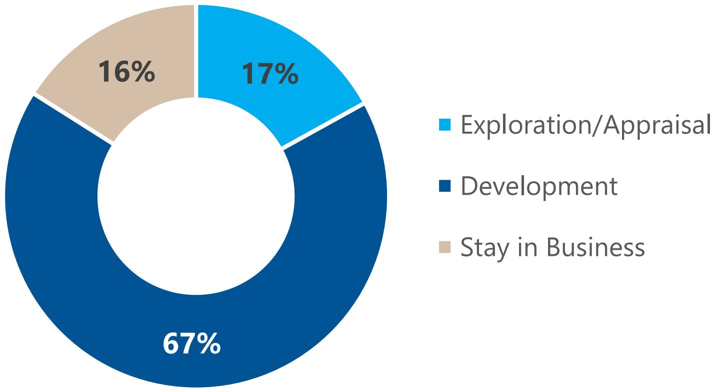
Gas and gas liquids production

- Broadly flat Cooper Basin gas/gas liquids production
- Start-up of Waitsia Stage 1 expansion in H1 FY21
- Connection of Beharra Springs Deep 1 around mid FY21
- Natural field decline in Victorian Otway Basin ahead of new wells in FY22+
- 23-day shutdown at Otway currently planned for November 2020
- Natural field decline in FY21 at Kupe ahead of compression project completion
- Gas customer nominations remain an important driver in production volumes

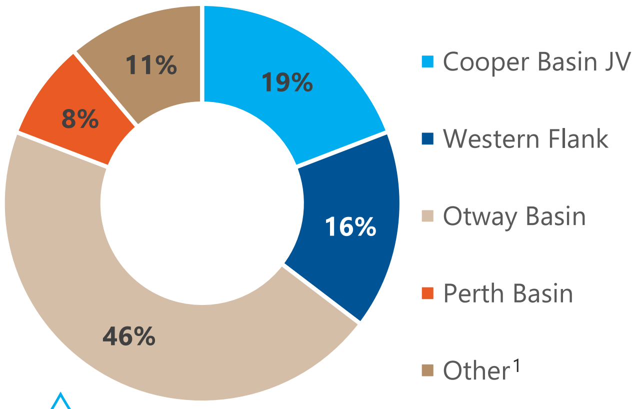
FY21 capital expenditure guidance splits

Investment focus remains on Cooper Basin and Victoria

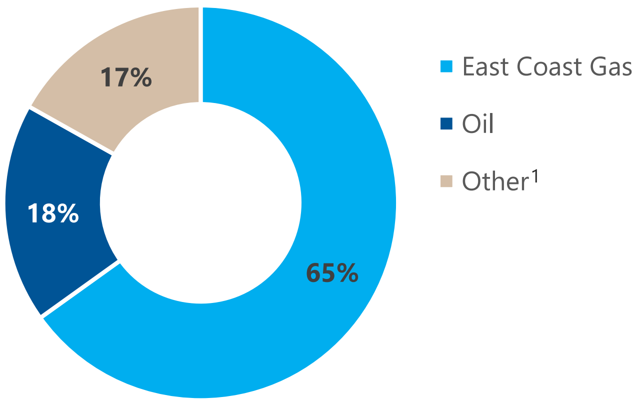
Capital expenditure by type



.. by asset group



.. and by target market



FY21 investment relative to FY20 expenditure

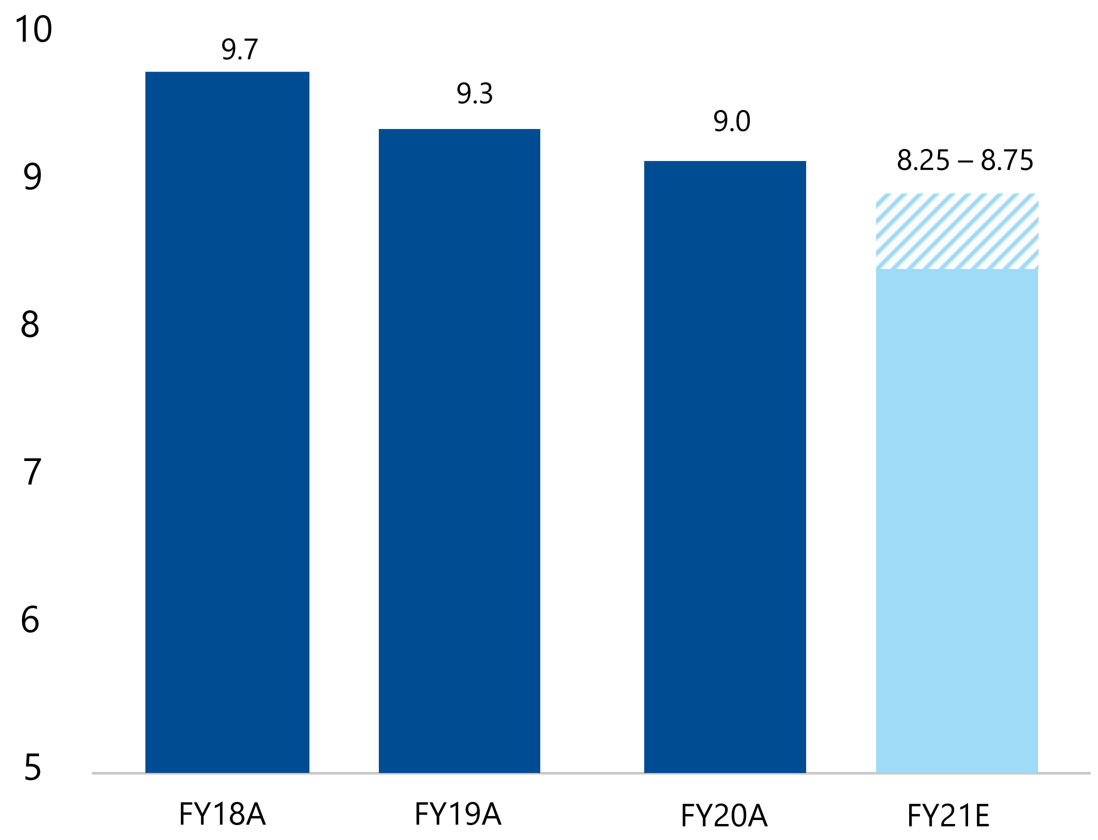
- Reduction in Cooper Basin drilling activity
- Anticipated start of offshore Victorian Otway Basin drilling (estimate assumes mid FY21 start date) and drilling of Enterprise 1 exploration well
- Increased investment in WA in anticipation of Waitsia Stage 2 FID
- Almost two thirds of investment is directed at gas supplies for the East Coast gas market
- Reduction in exploration/appraisal investment as focus is on development activities
- **Approximately 40% of FY21 capital expenditure will generate production volumes in FY21. The remaining 60% is targeting production growth in future years**

1. Other represents New Zealand, Western Australia and Frontier.

Field operating costs

Targeting a 3-7% reduction in FY21 field operating cost/boe vs FY20 levels

Average field operating costs/boe – historic and outlook
(A$/boe)



Opportunities for further reduction in field operating costs

- Beach has continued to drive costs out of the business post the Lattice acquisition to maintain its mantle as a low cost operator
- $30 million per annum reduction in direct controllable operated cost achieved in FY20, as per previously released target
- Staff and contractor reductions made in June 2020 to align with revised FY21 investment profile
- FY20 field operating cost of $9.0/boe
- FY21 field operating cost guidance range is $8.25-8.75/boe
  - ✓ Western Flank oil to be maintained below $5/boe
  - ✓ Western Flank gas below $3/boe

Key takeaways

Summary

A high margin and high growth business

Solid FY20 result in challenging conditions

- ✓ Responded quickly to COVID-19 threat
- ✓ 178 wells drilled at 81% overall success rate
- ✓ FY20 production 26.7 MMboe, within 1% of guidance
- ✓ FY20 underlying EBITDA of $1,108 million
- ✓ FY20 underlying NPAT of $461 million
- ✓ ROCE >19%
- ✓ Final dividend of 1.0 cent per share

Entering FY21 with a strong foundation

- ✓ **Balance sheet in net cash position**
- ✓ **High margin business** – no material impairments at reduced Long Term oil price outlook[1] (US$60/bbl)
- ✓ **Resilient and growing 2P reserves base**
  - 352 MMboe 2P reserves
  - 214% 2P reserves replacement ratio in FY20
  - 2P reserves life increased to 13.2 years
  - Minimal reserves risk at lower oil prices
- ✓ **Gas business provides material revenue certainty**

Beach growth plans slowed, but unchanged

- ✓ Planned FY21 capital expenditure reduced by >30%
- ✓ Prudent slow down in investment activity to reflect COVID-19 risks and uncertainty
- ✓ **New rig contract signed with Diamond Offshore**, drilling planned to commence Dec '20 – Mar '21
- ✓ **Waitsia Stage 2 FID in December 2020 quarter** with LNG export of up to 1.5 mtpa via NWS
- ✓ Ironbark 1 exploration well to spud in Q2 FY21
- ✓ **Beach can invest through the cycle**. Forecast peak net gearing <10% at US$30/bbl over next 5 years
- ✓ **Targeting 37 – 43 MMboe production in FY25**
- ✓ **$2.1 billion forecast 5 year FCF at reduced commodity price outlook[1]**

Refer to disclaimer on slide 2 for information relating to assumptions

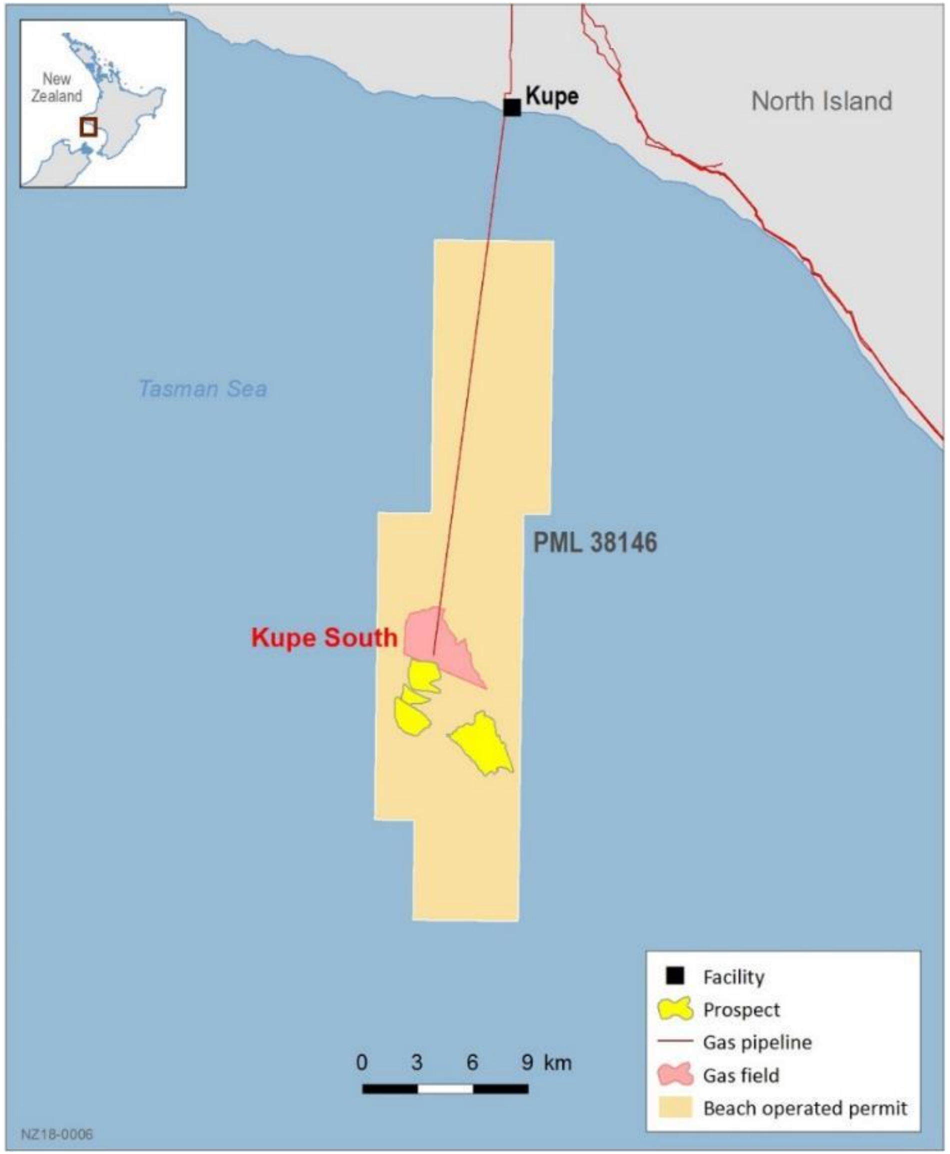
1. Excludes oil tolls, tariffs and royalties.

FY20 FULL YEAR RESULTS AND OUTLOOK PRESENTATION

Q & A

FY20 FULL YEAR RESULTS PRESENTATION

Appendices



Kupe

Beach 50% interest and operator

beach

FY20 outcomes

- FID of Kupe compression project
- Compression required to increase production back to facility capacity of 77 TJ/d
- Major shutdown completed in November, safely, on time and budget
- Well intervention campaign in February delivered rate uplift and increased reserves
- Short term gas sales executed to maximise gas sales through the year
- 99.5% average facility reliability for the year

Proposed FY21 activities

- Kupe compression project online early FY22
- Evaluation of development and near field exploration (NFE) drilling opportunities to maintain plateau production beyond FY24

Strategic considerations

- Kupe supplies 15% of NZ gas market and produces ~50% of NZ LPG supply
- Long life asset generating positive free cash flow
- Operational synergies with other Taranaki based operators

Economic considerations

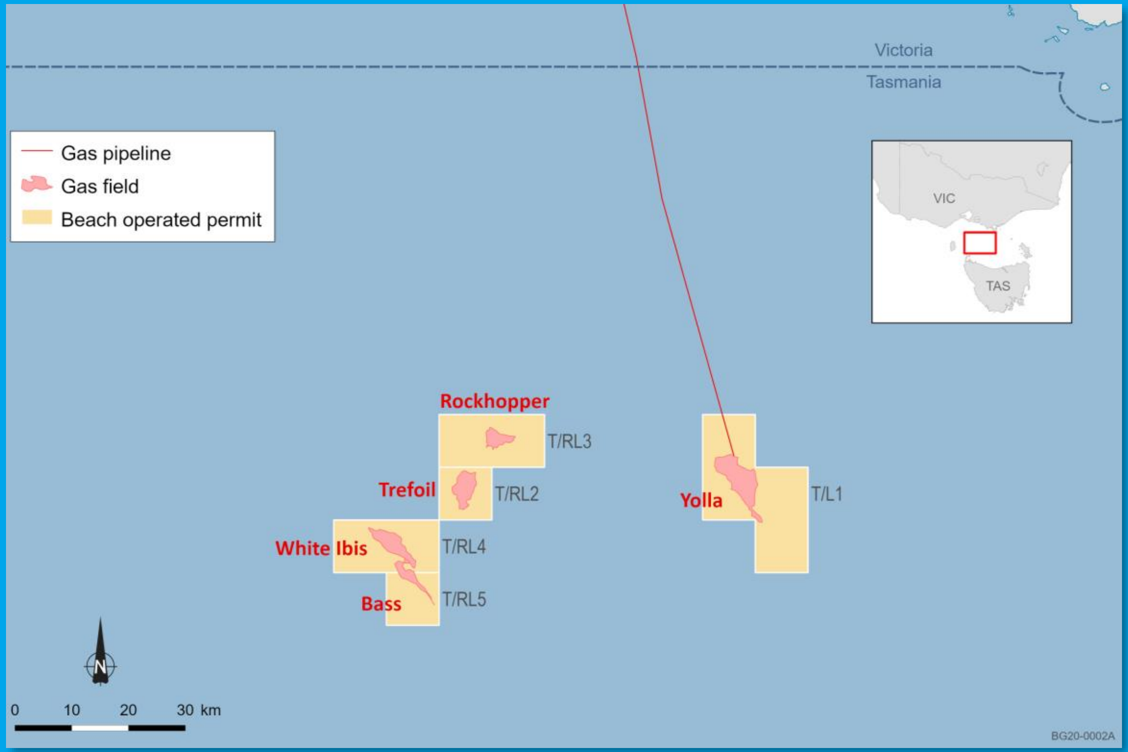
- IRR of compression project >50%
- Target maintaining sufficient deliverability to keep gas processing facility full for as long as possible
- Evaluate development well(s) to target undeveloped 2P reserves
- Evaluate NFE opportunities targeting additional resources to extend field life

Bass Basin and SA Otway Basin

Evaluating further gas development opportunities

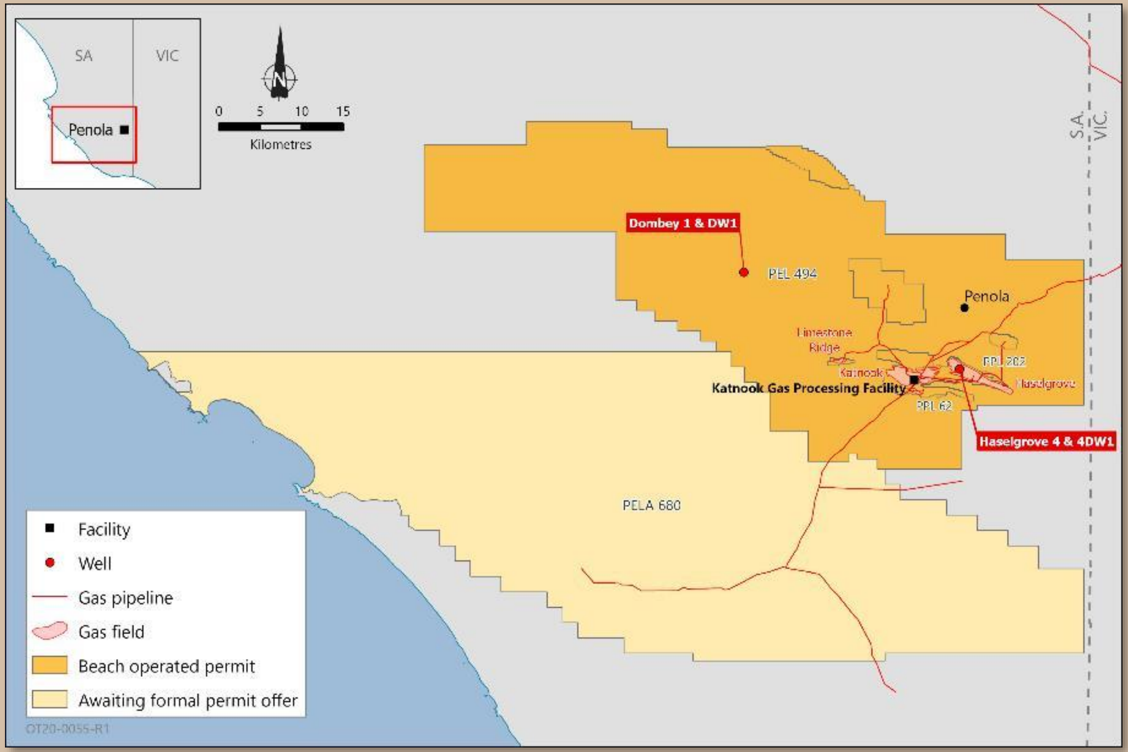
Bass Basin proposed FY21 activities

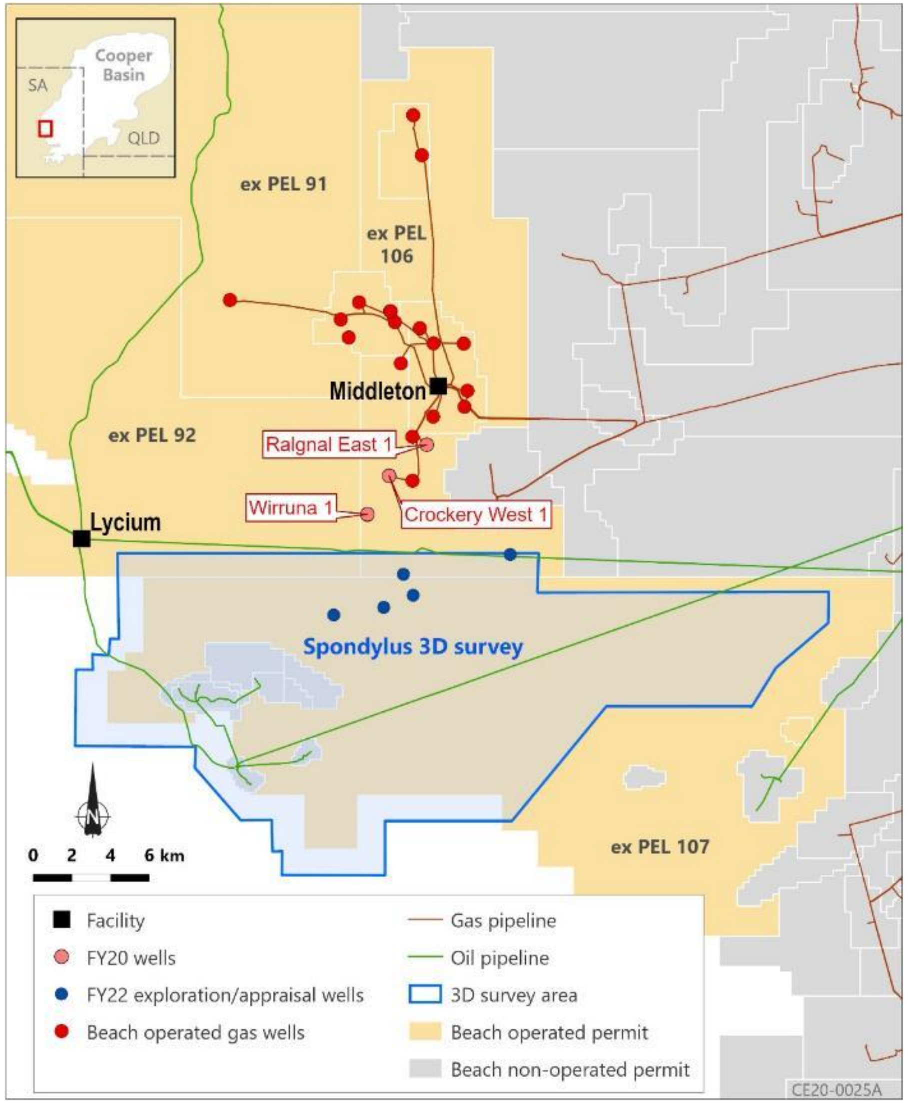
- Complete concept select studies for Trefoil development
- Target FEED entry
- Prepare for 3D seismic over White Ibis and Bass



SA Otway Basin proposed FY21 activities

- Progress planning and design of Dombey 3D seismic survey
- Integration of Haselgrove 4 DW1 result into Haselgrove field development plan
- Maturation of Penola Trough prospect and lead seriatim





Western Flank Gas

Liquids rich gas production with expansion potential

FY20 outcomes

- Debottleneck condensate handling at Middleton
- Three new term GSAs in place covering CY20/21
- Sufficient deliverability is available to keep facility full until FY22 following positive drilling results in FY19
- Prioritised production from higher liquids content Lowry field

Proposed FY21 activities

- Continue to high grade exploration and appraisal targets
- No drilling planned in FY21, drilling priority remains on Western Flank Oil
- Exploration and development drilling plans now expected in FY22

Strategic considerations

- Increased supply for the East Coast gas market
- Further upside potential within ex PEL 106 and 107 (Beach 100% interest)
- Middleton expansion potential subject to exploration success

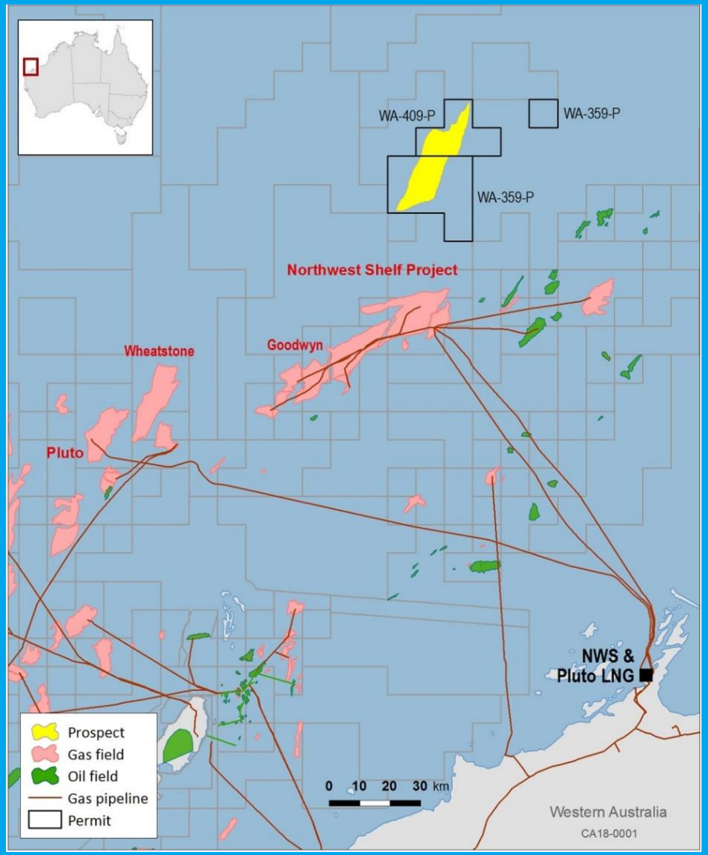
Economic considerations

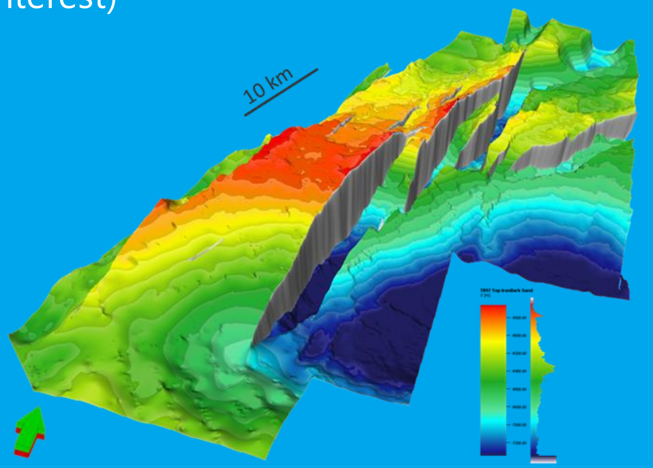
- Most development well IRRs >100%
- Highly economic wells at current oil prices
- Liquids rich gas (up to 50 bbl/MMscf)
- Liquids revenues similar to gas revenues
- Gas sold to east coast domestic gas customers at market prices

Frontier exploration

Two material exploration prospects to be drilled in the next 18 months

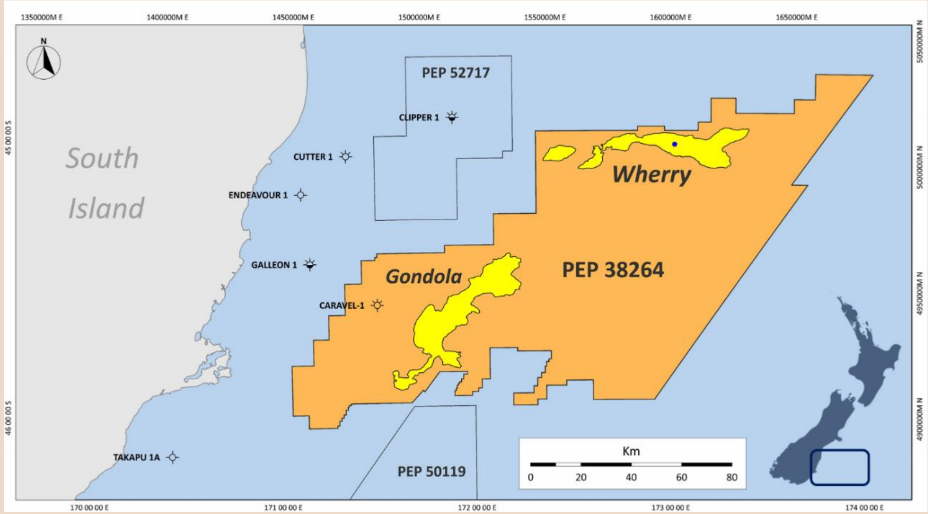
Ironbark – Carnarvon Basin (Beach 21% interest)





- Large gas prospect within 50km of existing NWS infrastructure
- Targeting deeper Mungaroo reservoirs; the primary reservoirs at Gorgon
- Drilling currently expected to commence in October 2020
- Beach share of drilling cost ~$35 million

Wherry – Canterbury Basin (Beach 37.5% interest, operator)



- Working towards an H1 FY22 drill date[1,2]
- Well location agreed by JV during H1 FY20, pre-drill marine survey completed
- Wherry is a large gas-liquids prospect with follow-up potential

[1] Pending JV & management approvals, rig tender and contracting.
[2] Pending NZ regulator approvals.

Beach Energy portfolio

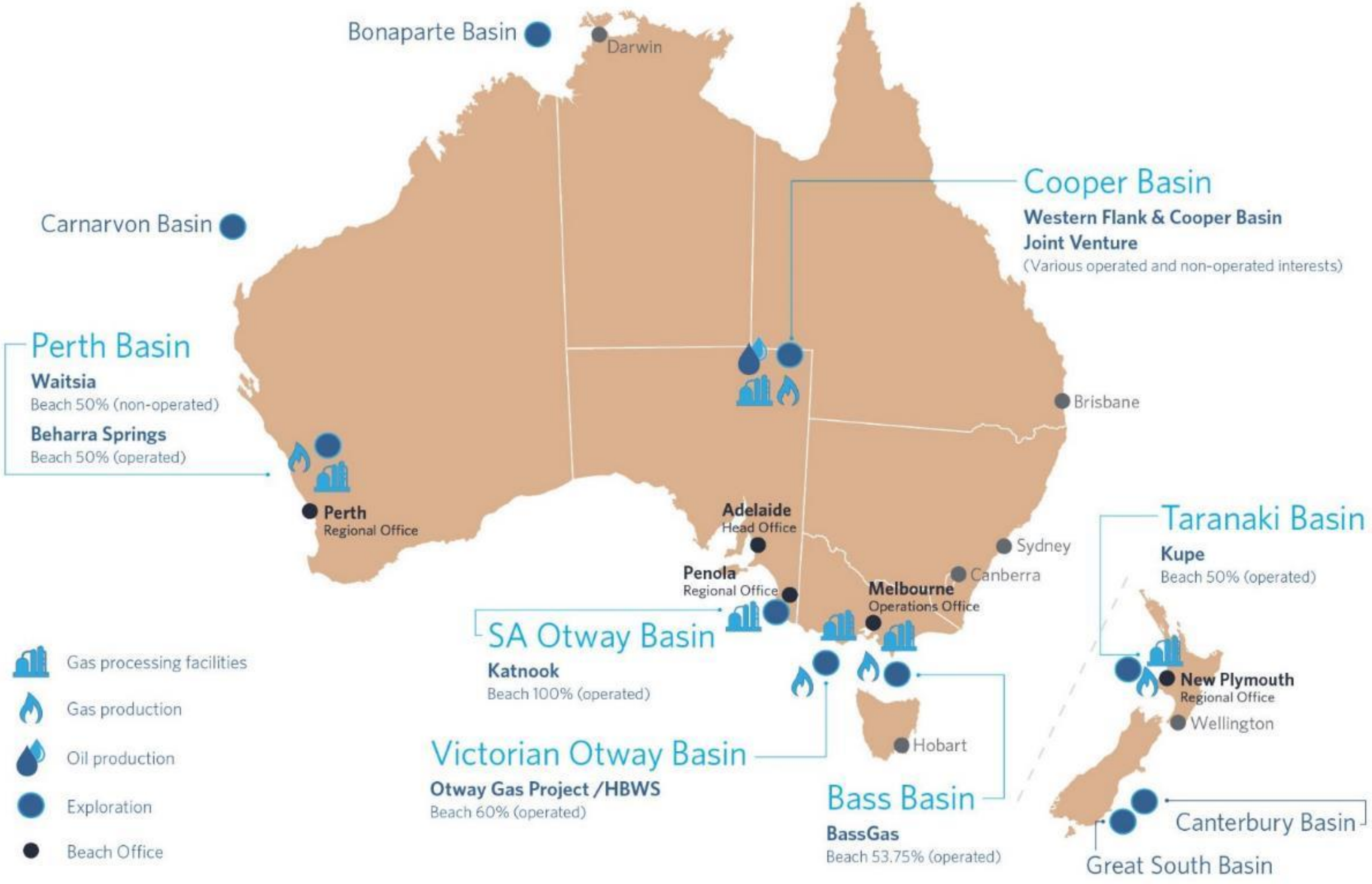
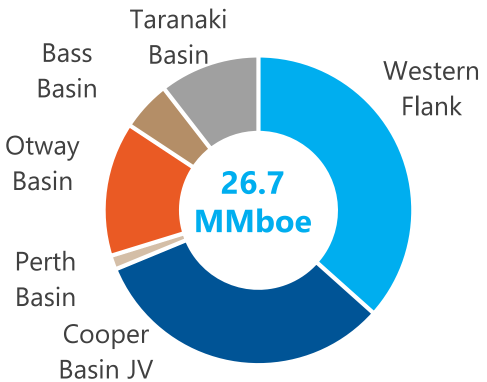


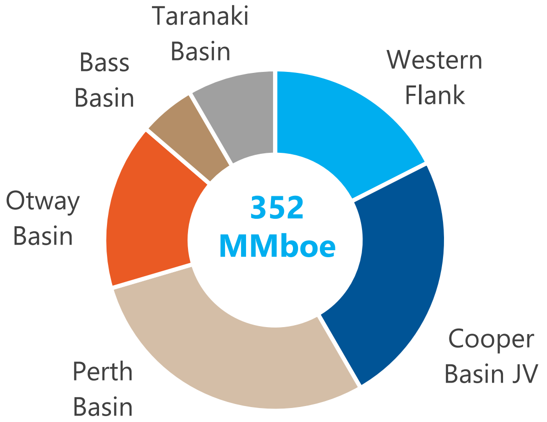
Illustration not to scale. Ownership percentages provided are Beach's ownership of the producing assets in the respective regions.

GD20-0013a

FY20 production



FY20 2P reserves



Reconciliation of NPAT to Underlying NPAT[1]

$ millions

	FY19	FY20	Change
Net Profit After Tax	577	**501**	**(13%)**
Gain on reversal of provision for onerous commitment	-	**(38)**	
Gain on asset sales	(20)	**(18)**	
Impairment of assets	-	**2**	
Tax impact of the above	3	**14**	
Underlying Net Profit After Tax (NPAT)	560	**461**	**(18%)**

Note: Due to rounding, figures and ratios may not reconcile to totals.

1. Underlying results in this report are categorised as non-IFRS financial information provided to assist readers to better understand the financial performance of the underlying operating business. They have not been subject to audit or review by Beach's external auditors, however have been extracted from the audited financial statements.

Underlying EBITDAX, EBITDA, EBIT, NPBT and NPAT[1]

$ millions

	FY19	FY20	Change
Underlying EBITDAX	**1,375**	**1,129**	**(18%)**
Exploration expense	-	(21)	
Underlying EBITDA	**1,375**	**1,108**	**(19%)**
Depreciation and amortisation	(527)	(455)	
Underlying EBIT	**848**	**653**	**(23%)**
Finance expenses	(62)	(16)	
Interest income	4	2	
Underlying Net Profit Before Tax (NPBT)	**790**	**639**	**(19%)**
Tax	(230)	(178)	
Underlying Net Profit After Tax (NPAT)	**560**	**461**	**(18%)**

Note: Due to rounding, figures and ratios may not reconcile to totals.

1. Underlying results in this report are categorised as non-IFRS financial information provided to assist readers to better understand the financial performance of the underlying operating business. They have not been subject to audit or review by Beach's external auditors, however have been extracted from the audited financial statements.

AASB 16 lease impacts

Adopted 1 July 2019

FY20 Financial Statement disclosures

Balance Sheet	▪ Lease assets $59m ▪ Lease liabilities $62m
Profit & Loss	▪ Depreciation of lease assets[1] $22m ▪ Interest on lease liabilities $3m ▪ Other income from JV lease recoveries $16m
Cash Flow	▪ Net operating cash inflows $12m ▪ Financing cash outflows $54m

Note: Due to rounding, figures and ratios may not reconcile to totals.
1 Represents depreciation expense ($57m), offset by capitalised depreciation for lease assets related to capital spend ($35m)

Net impact of AASB 16

- Accounting change only:
  - No net cash impact
  - NPAT impact of $2m decrease
  - Immaterial net asset impact
- Lease payments relating to operations shift operating expenses to depreciation and interest expense, and other income related to joint venture recoveries
- Lease payments relating to capital spend shift capital expenditure additions to depreciation and other income related to joint venture recoveries, with Beach's share of depreciation then capitalised
- Majority of Lease balances relate to rigs, property and transportation

FY21 key milestones and catalysts[1]

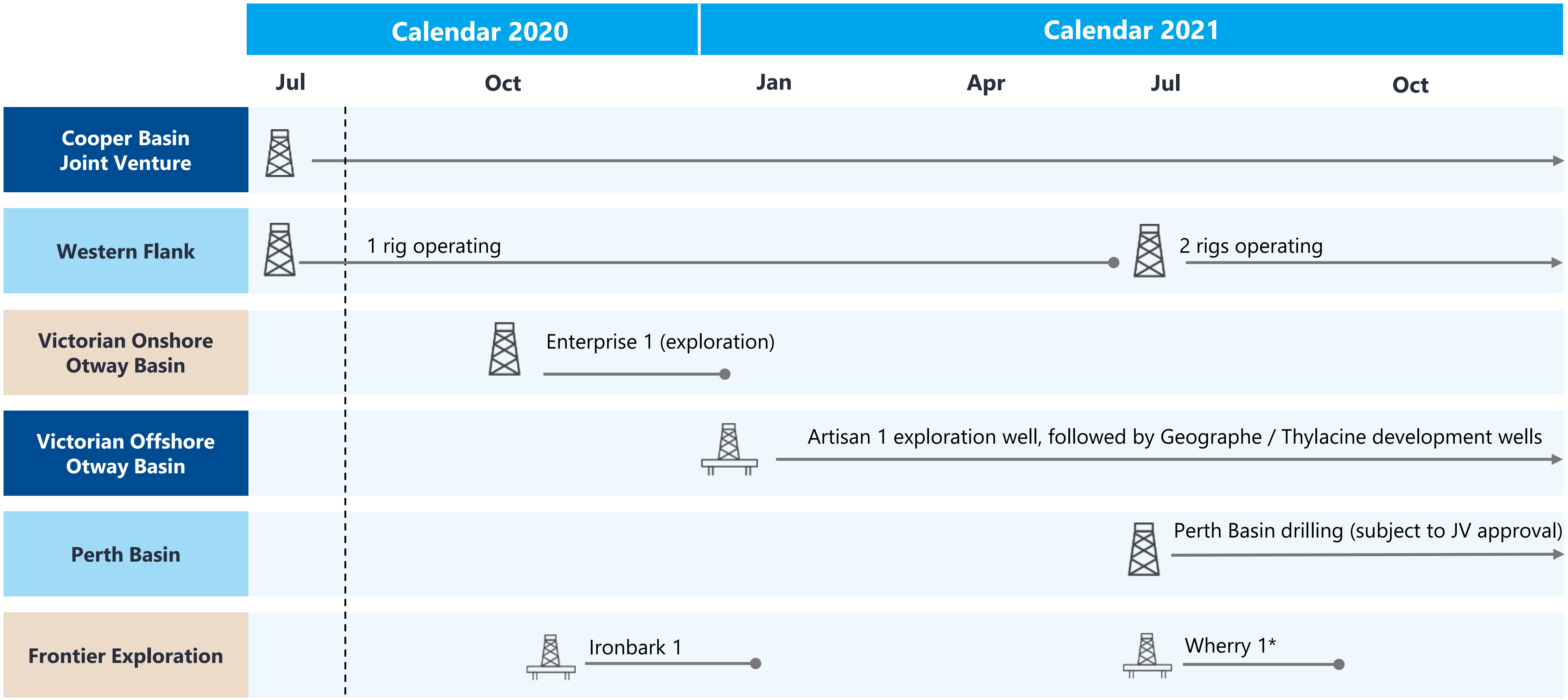
Event	FY21 expected timing			
	Q1	Q2	Q3	Q4
Waitsia Stage 1 expansion completion	◆			
Waitsia Stage 2 FID		TBC		
Victorian Otway repricing completion			TBC	
Ironbark 1 exploration well		TBC		
Enterprise 1 exploration well		TBC		
Artisan 1 exploration well			TBC	
Geographe/Thylacine development wells				TBC

TBC = "To Be Confirmed"

1. Beach's illustrative milestone and catalyst schedule is subject to change.

Near term work program[1]

Flexibility retained



1. Beach's illustrative rig schedule is subject to change.

* Wherry timing subject to rig availability and JV approval

Summary of East Coast gas contracts at 30 June 2020

Beach gas sales to progressively be re-priced at prevailing market pricing

Asset	FY20 Volume (PJ)	Counterparty	Basis	End date	Effective Price Review Date	Market pricing FY21	FY22	FY23	FY24	FY25
Cooper Basin JV		Origin Energy[1]	Oil-linked with downside protection	Jun '25						
Cooper Basin JV	36.3	Origin (Lattice GSA)[2]	Fixed price + CPI until repricing	Jun '30	1 July 2021					
Cooper Basin JV Ethane		Qenos[3]		2025						
Western Flank Gas	8.6	Various[4]		Dec '21						
Victorian Otway		Origin (Lattice GSA)[2]	Fixed price + CPI until repricing	Jun '33	1 July 2020					
Victorian Otway	18.4	Origin (Toyota GSA)[5]								
Victorian Otway		AGL[6]		2021						
BassGas	6.1	Alinta[7]		Dec '21						
SA Otway	0.9									
Total (Beach share)	**72.9**									

1. BPT ASX releases 10 April 2013 and 1 July 2015.
2. BPT ASX release 28 September 2017.
3. BPT media release dated 30 January 2020.
4. All Western Flank gas is currently supplied at market prices.
5. BPT Quarterly Report 29 Oct 2018, BPT and Origin agreed a price increase in accordance with the price reviews provisions of the gas sales agreement.
6. Source: AGL FY15 Interim Results presentation, 11 February 2015.
7. BPT ASX release 29 January 2020.

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