Gas Play with Optionality

Tamboran (TBN) is a gas exploration company that aims to establish new 2P reserves and gas production out of the Beetaloo Basin (NT) to supply the Australian domestic and Asian LNG markets. We believe TBN's key value driver will be to develop proven and probable reserves (2P) as quickly as possible and take advantage of its end-market options. With exploration kicking off for TBN's two assets, we expect near-term news flow to benefit the share price.

Quality resource, high probability of discovery

TBN has a 25% interest in EP161 (operator Santos) and is sole owner and operator at EP136. The assets have a high probability of discovery driven by early indications from drilling and flow testing at EP161 confirming the elevated productivity potential; the Beetaloo Basin having already been de-risked through an earlier drilling program by Origin/Falcon; the Federal Government incentivising Beetaloo development to grow the regional economy and ensure gas supply; and their status as a high-quality gas resource, with low levels of CO_2 supporting TBN's environmental goals.

Supportive macro picture

The gas market is forecast to be undersupplied going forward given low returning coal seam gas (CSG) is being directed into LNG plants, existing gas contracted into the southern states, and limited new discoveries. TBN is targeting both the undersupplied LNG markets and to supply the domestic markets by CY25 through a proposed pipeline to be constructed by Jemena. This should be supported by a reserve booking of ~3 Tcf by first gas at EP136 (or earlier with sanction of the pilot program).

Backing management/board experience

The board and management have previous experience in developing similar unconventional plays in the US and Australia. The working interest with Santos will provide knowledge sharing opportunities. Technical learnings, fixed cost leverage and scale should see well costs fall rapidly in the initial years of drilling.

Funding looks adequate for initial exploration

TBN expects to meet costs of its initial exploration program (3 wells + seismic, ~$70m) with existing funding. TBN has various additional funding options: tapping the equity market, asset farm downs or sales. We forecast TBN will be FCF positive by FY26.

Valuation: DCF implies at least 70% upside

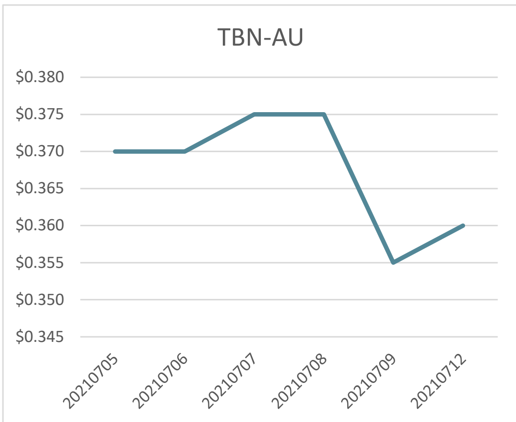
Our base case 12 month forward discounted cash flow valuation by asset is $0.61; giving upside of 70% from the current share price, potentially greater given we risk weight the assets by 10-15%. Comparing to peers on a 2P+2C basis, TBN is trading at $0.05/GJ vs peers at $0.82/GJ.

Tamboran Resources (TBN) is a gas exploration company with the aim to get new 2P reserves and gas production out of the Beetaloo Basin in the Northern Territory to the Australian domestic market and LNG Asian market.
http://www.tamboran.com/

Stock	TBN.ASX
Price	A$0.36
Market cap	A$235m
Valuation (per share)	A$0.61

News Flow and Catalysts	
July 2021	EP161 Tanumbrini #2H drilling completion
Sept 2021	EP161 Tanumbirini #2H and #3H flow test results
1HFY22	Drilling EP136 Maverick #1
CY23	Sanction of EP136 pilot program and possibly 2P reserve booking

TBN Share Price (A$)



Source: FactSet

Anita Costa
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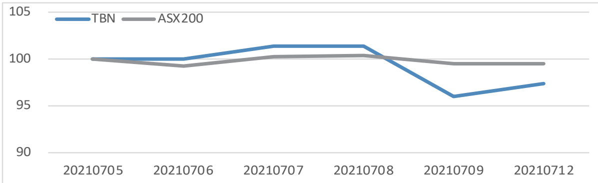
Financial Forecasts

Tamboran Resources — TBN-AU

Year end 30 June

MARKET DATA		
Price	**$**	**0.36**
52 week high / low	A$	0.34-0.40
Valuation	**A$**	**0.61**
Total return - 12 month	**%**	**68.6%**
Market capitalisation	A$m	235.0
Shares on issue (basic)	**m**	**652.9**
ESOP	m	37.0
Shares on issue (diluted)	**m**	**689.8**

TBN Relative versus S&P/ASX 200



INVESTMENT FUNDAMENTALS		FY19A	FY20A	FY21E	FY22E	FY23E
EPS reported	¢	-16.4	-15.5	-0.6	-1.0	2.5
EPS reported diluted	¢	-14.3	-12.9	-0.6	-0.9	2.4
EPS underlying	**¢**	**-16.4**	**-15.5**	**-0.6**	**-1.0**	**2.5**
EPS underlying diluted	**¢**	**-14.3**	**-12.9**	**-0.6**	**-0.9**	**2.4**
EPS diluted growth	%		-6%	-96%	69%	-356%
P/E reported	**x**	**0.0**	**-2.1**	**-61.4**	**-36.3**	**14.2**
P/E underlying	**x**	**0.0**	**-2.1**	**-61.4**	**-36.3**	**14.2**
P/E underlying (diluted)	**x**	**0.0**	**-2.5**	**-64.9**	**-38.2**	**14.8**
Dividend	**¢**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Payout ratio	%	0.0%	0.0%	0.0%	0.0%	0.0%
Yield (Y/E/ spot)	**%**		**0.0%**	**0.0%**	**0.0%**	**0.0%**
Franking	%	0.0%	0.0%	0.0%	0.0%	0.0%
Gross Yield (Y/E/ spot)	**%**		**0.0%**	**0.0%**	**0.0%**	**0.0%**
Book value / share	¢	-27.4	-42.2	4.0	13.3	22.1
Price to book (NAV)	**x**	**0.0**	**-0.8**	**9.1**	**2.7**	**1.6**
NTA / share	¢	-27.4	-42.2	4.0	13.3	22.1
Price to NTA	**x**	**0.0**	**-0.8**	**9.1**	**2.7**	**1.6**
Year end shares	**m**	**93**	**94**	**653**	**656**	**808**
Average diluted shares	m	107	112	690	690	766
Year end share price	$	0.00	0.32	0.36	0.36	0.36
Market cap (Y/E / Spot)	$m	-	30	235	236	291
Net debt /(cash/funding)	**$m**	**-27**	**-6**	**-11**	**-43**	**-60**
Enterprise value	**$m**	**-27**	**24**	**224**	**193**	**232**
EV/EBITDAX	**x**	**7.4**	**-2.0**	**-66.0**	**-51.0**	**6.2**
Gearing (net debt / EBITDAX)	**x**	**7.4**	**0.5**	**3.2**	**11.3**	**-1.6**
Free cash flow	**$m**	**-6.5**	**-20.9**	**-16.9**	**-68.5**	**-48.7**
Free cash flow per share	¢	-6.9	-22.3	-2.6	-10.5	-6.6
Price to free cash flow	**x**	**0.0**	**-1.4**	**-13.9**	**-3.4**	**-5.4**
Free cash flow yield	**%**		**-70%**	**-7%**	**-29%**	**-18%**

ASSUMPTIONS		FY19A	FY20A	FY21E	FY22E	FY23E
Domestic gas price - SE	$/GJ				$ 8.00	$ 8.50
Domestic gas price - NT	$/GJ				$ 6.00	$ 6.50
Gas Production						
EP161	PJ	0	0	0	1	3
EP136	PJ	0	0	0	2	8
Total	**PJ**	**0**	**0**	**0**	**3**	**11**

VALUATION		FY22	Low	Base	High
Discount rate used in NPV calculations			12.0%	9.6%	8.0%
EP161 25%, risked at 15%	$m		156	224	287
EP136 100%, risked at 10%	$m		138	179	212
Assets	**$m**		**294**	**403**	**499**
Site Restoration	$m		-15	-15	-15
Corporate Costs Allocation	$m		-58	-70	-79
Enterprise Value	**$m**		**221**	**318**	**404**
Net Debt / (Cash)	$m		67	67	67
Government Funding	$m		21	21	21
Options	$m		12	12	12
Equity	**$m**		**321**	**419**	**505**
Diluted Shares on Issue	m		690	690	690
Per Share	**$**		**0.47**	**0.61**	**0.73**
Share price return	%		29%	69%	103%
Dividend Yield	%		0%	0%	0%
Total Shareholder Return	**%**		**29%**	**69%**	**103%**
Peers EV/2P+2C	$			0.82	
Implied EV for TBN	$m			2395	
Implied Share Price for TBN	$			$ 3.62	

Source: MST Access and TBN

PROFIT AND LOSS		FY19A	FY20A	FY21E	FY22E	FY23E
Product Sales	**$m**	**0.0**	**0.0**	**0.0**	**0.0**	**74.1**
Other income	$m	0.0	0.0	0.0	0.0	0.0
Total Income	**$m**	**0.0**	**0.0**	**0.0**	**0.0**	**74.1**
Operating costs	$m	-3.6	-12.4	-3.4	-3.8	-37.0
EBITDAX	**$m**	**-3.6**	**-12.4**	**-3.4**	**-3.8**	**37.1**
Exploration expenditure	$m	0.0	0.0	0.0	0.0	0.0
EBITDA	**$m**	**-3.6**	**-12.4**	**-3.4**	**-3.8**	**37.1**
Depreciation & Amortisation	$m	0.0	-0.1	-0.4	-2.7	-10.6
EBIT	$m	-3.6	-12.5	-3.8	-6.5	26.5
Net interest	$m	-11.8	-2.0	0.0	0.0	0.0
Pretax Profit	**$m**	**-15.4**	**-14.5**	**-3.8**	**-6.5**	**26.5**
Tax expense (30%)	$m	0.0	0.0	0.0	0.0	-8.0
NPAT (underlying)	**$m**	**-15.4**	**-14.5**	**-3.8**	**-6.5**	**18.6**
Impairments / Other	$m	0.0	0.0	0.0	0.0	0.0
Reported NPAT	**$m**	**-15.4**	**-14.5**	**-3.8**	**-6.5**	**18.6**
EBITDA margin	%					50%
EBIT margin	%					36%
NPAT margin	%					25%
EBITDA growth	%		345%	27%	112%	-979%
EBIT growth	%		348%	31%	170%	-409%
NPAT growth	%		94%	26%	170%	-286%

BALANCE SHEET		FY19A	FY20A	FY21E	FY22E	FY23E
Cash	$m	26.5	5.6	10.8	10.1	26.9
Receivables	$m	0.1	0.5	1.5	1.6	1.7
Inventory	$m	0.0	0.0	0.0	0.0	0.0
Other	$m	0.0	0.0	0.0	0.0	0.0
Current assets	**$m**	**26.6**	**6.1**	**12.4**	**11.8**	**28.7**
Exploration phase expenditure	$m	4.5	15.7	17.0	78.2	158.3
Oil and Gas assets	$m	0.0	2.6	2.4	9.2	18.1
Other	$m	0.0	0.7	0.3	-2.4	-13.0
Non current assets	**$m**	**4.5**	**19.0**	**19.7**	**85.0**	**163.4**
Total Assets	**$m**	**31.1**	**25.1**	**32.1**	**96.7**	**192.1**
Accounts Payable	$m	0.6	4.1	2.9	6.3	9.6
Borrowings	$m	0.0	0.0	0.0	0.0	0.0
Other	$m	0.4	0.5	1.1	1.1	1.1
Current liabilities	**$m**	**0.9**	**4.5**	**4.0**	**7.4**	**10.7**
Borrowings	$m	0.0	0.0	0.0	0.0	0.0
Provisions	$m	0.0	2.3	0.0	0.0	0.0
Other	$m	**55.7**	**57.8**	**2.2**	**2.3**	**2.4**
Non current liabilities	**$m**	**55.8**	**60.1**	**2.2**	**2.3**	**2.4**
Total Liabilities	**$m**	**56.7**	**64.7**	**6.2**	**9.7**	**13.1**
Equity	$m	20.5	20.5	91.0	153.0	208.0
Retained earnings	$m	-49.8	-64.3	-68.1	-74.6	-56.0
Reserves / Other	$m	3.7	4.2	2.9	8.7	27.0
Total equity	**$m**	**-25.6**	**-39.6**	**25.8**	**87.0**	**179.0**

CASH FLOW		FY19A	FY20A	FY21E	FY22E	FY23E
EBITDAX	$m	**-3.6**	**-12.4**	**-3.4**	**-3.8**	**37.1**
Change in working capital	$m	-11.6	1.4	-2.1	3.3	3.2
Net interest	$m	11.8	2.1	0.0	0.0	0.0
Tax paid	$m	0.0	0.0	0.0	0.0	0.0
Other	$m	0.0	0.0	0.0	0.0	0.0
Operating cash flow	**$m**	**-3.4**	**-8.9**	**-5.5**	**-0.5**	**40.3**
Capital expenditure - exploration	$m	-3.1	-11.2	-1.3	-61.2	-80.1
Capital expenditure - assets	$m	0.0	-0.8	-10.0	-6.8	-8.9
Net investment / Other	$m	0.0	0.0	0.0	0.0	0.0
Investing cash flow	**$m**	**-3.1**	**-12.0**	**-11.3**	**-68.0**	**-89.0**
Change in Equity	$m	0.0	0.1	22.1	61.9	55.0
Increase / (decrease) in borrowings	$m	0.0	0.0	0.0	0.0	0.0
Dividend / other	$m	31.3	-0.1	0.0	5.9	10.5
Financing cash flow	**$m**	**31.3**	**0.0**	**22.1**	**67.8**	**65.5**
Change in Cash / FX	$m	24.8	-20.9	5.2	-0.7	16.8
Cash year end		**26.5**	**5.6**	**10.8**	**10.1**	**26.9**

Investment Thesis: Promising Gas Resource with Choice of Markets

Gas explorer Tamboran Resources (TBN) aims is to establish new 2P reserves and gas production out of the Beetaloo Basin in the Northern Territory (NT) to supply the Australian domestic market and the Asian liquefied natural gas (LNG) market. The key value driver for TBN will be developing proven and probable reserves (2P) as quickly as possible and the benefit of its end-market optionality. In our view, management has the skills to develop the resource while keeping costs in check, and the company has established useful and synergistic partnerships. We expect positive news flow as the exploration program begins, and value the stock at $0.61 based on our DCF analysis.

Quality Assets: High Productivity Potential + Low Risk + Government Support

TBN has a 25% interest in EP161 (alongside the operator Santos) and is the sole owner and operator at EP136 (see Exhibit 1). The value of the assets is driven by proximity to end markets, quality, and growth potential through extraction. Early indications from drilling at EP136 and the Tanumbirini #1 flow test confirm high productivity potential. The Beetaloo Basin is already derisked through an earlier drilling program by Origin/Falcon. The Federal Government is incentivising development in the Basin to encourage more regional economic growth and ensure gas supply. The high-quality gas resource, given what appears to be low levels of CO_2, should aid the 'E' in TBN's ESG aspirations.

Exhibit 1 – Overview of TBN's assets

Asset and interest	EP161	EP136
TBN's interest	25%	100%
Operator	Santos	Tamboran
Net prospective and contingent resource (NSAI)	12.3 Tcf	19.0 Tcf

Source: TBN, NSAI (Netherland Sewell and Associates).

Supportive Industry Environment: Undersupplied Markets, Limited Discoveries

The gas market is undersupplied from low returning CSG wells directed into the LNG plants, existing gas already being contracted into the southern states, and limited new discoveries. TBN is targeting both the undersupplied LNG markets and to supply the domestic markets by CY25 through its MOU with Jemena that is planning on constructing a pipeline to the Eastern Australian markets. This should be supported by a reserve booking of ~3 Tcf by first gas at EP136, around CY25 (or potentially earlier with sanction of the pilot program in CY23).

Experienced Management and Board Can Hit the Ground Running, Cut Costs Fast

The Board and management have previous experience in developing similar unconventional plays in the US and Australia. Added to this is the knowledge that will be shared from the working interest with Santos. Technical learnings, fixed cost leverage and scale should see well costs improve rapidly in the initial years of drilling.

Cash Funding Optionality, with TBN Free Cash Flow (FCF) Positive by FY2026

TBN's initial exploration program of 3 wells plus seismic (~$70m) should be met by the existing funding in place including funds raised from the initial public offering (IPO). If there are slippages in assumptions, TBN has various funding options including tapping the equity market and asset farm downs or sales. Based on our forecasts, we expect TBN to be FCF positive by FY2026.

Valuation

Our base-case 12-month forward sum of the parts based on discounted cash flow valuation by asset is $0.61, giving potential upside of 70% from the current share price. Given we currently risk weight the assets by 10-15%, there is significantly greater return long term. TBN is currently trading EV/Reserves at $0.05/ GJ vs listed peers at $0.82/GJ.

Given the various assumptions that go into an energy stock valuation we believe it is prudent to consider sensitivities:

- +/-10% to the end sale price would see the valuation change +/-31% to $0.42/$0.79. A 10% rise in the selling price would see TBN FCF positive in FY24, 2 years ahead of our expectations, while a 10% fall, would push out FCF positive to FY29.
- +/-1 percentage point change in well costs would see the valuation change -/+4% to $0.63/$0.58
- a 12-month delay in drilling at EP136 would see the valuation change -14% to $0.52, leave TBN short an additional $19m funding, and delay FCF another year to FY27.
- If the gas from EP136 goes to LNG backfill rather than SE domestic gas market, the valuation improves by 70% to $1.03.

Potential Near-Term News Flow and Catalysts

- Drilling program at EP161 with Tanumbirini #2 expected completion July 2021, along with #3H flow test results expected September 2021.
- Success in receiving funds from the Beetaloo Cooperative Drilling Program
- Drilling of EP136 with Maverick #1, 1HFY22
- Sanction of EP136 pilot program, likely CY23
- Signing of early gas sales HOA
- 2P reserves booked, likely CY25. Initial estimates could come ahead of first gas at time of pilot sanction in CY23/24

Risks

For a more comprehensive detail on the risks, see page 26.

The company and share price face a range of risks, including:

- company-specific risks such as management issues, relationships with business partners, and timing, as well as the extent and quality of the resource vs. expectations
- financial risks such as funding, costs
- plant construction and commissioning
- reserve life
- production decline rates
- competition from LNG imports to Eastern Australia and other domestic gas discoveries impacting final gas pricing
- listed company risks such as significant shareholder selling
- environmental and operational risks
- regulatory risks
- macroeconomic risk.

History of Tamboran

The company was founded in 2009 by existing board member, Patrick Elliott. He was inspired by what was happening in North America with unconventional energy significantly adding to the energy equation and believed it could reasonably happen elsewhere. The company aggregated assets to make this a global energy play with acreage in Australia, Turkey, Myanmar, UK, Northern Ireland and Botswana. Today, only the Beetaloo EP161 asset remains.

Overall Asset Size: Engineers' Best Estimate for Gas Resource = 31.3 Tcf

The 'best estimate' of TBN's independent reservoir engineers (Netherland Sewell and Associates) for net prospective gas resource is 31.3 Tcf, with a range of 18.3–62.6 Tcf. Note that the best estimate is closer to the lower end of the range.

Exhibit 4 – Net prospective gas and condensate resources, 31 January 2021

Un-risked Net to the Company	Prospective (Bcf) EP161		Prospective (Bcf) EP136		TOTAL (Bcf)	
Reservoir	**Gas Resource**	**Condensate**	**Gas Resource**	**Condensate**	**Gas Resource**	**Condensate**
Velkerri C	3,492	26	6,050	50	9,542	76
Velkerri B	6,526	34	9,698	49	16,224	83
Velkerri A	2,078	11	3,037	15	5,115	26
Lower Kyalla	217	5	232	5	449	10
TOTAL	**12,313**	**76**	**19,017**	**119**	**31,330**	**195**
Low estimate	7,100		11,200		18,300	
High estimate	24,800		37,800		62,600	

Source: Netherland Sewell and Associates.

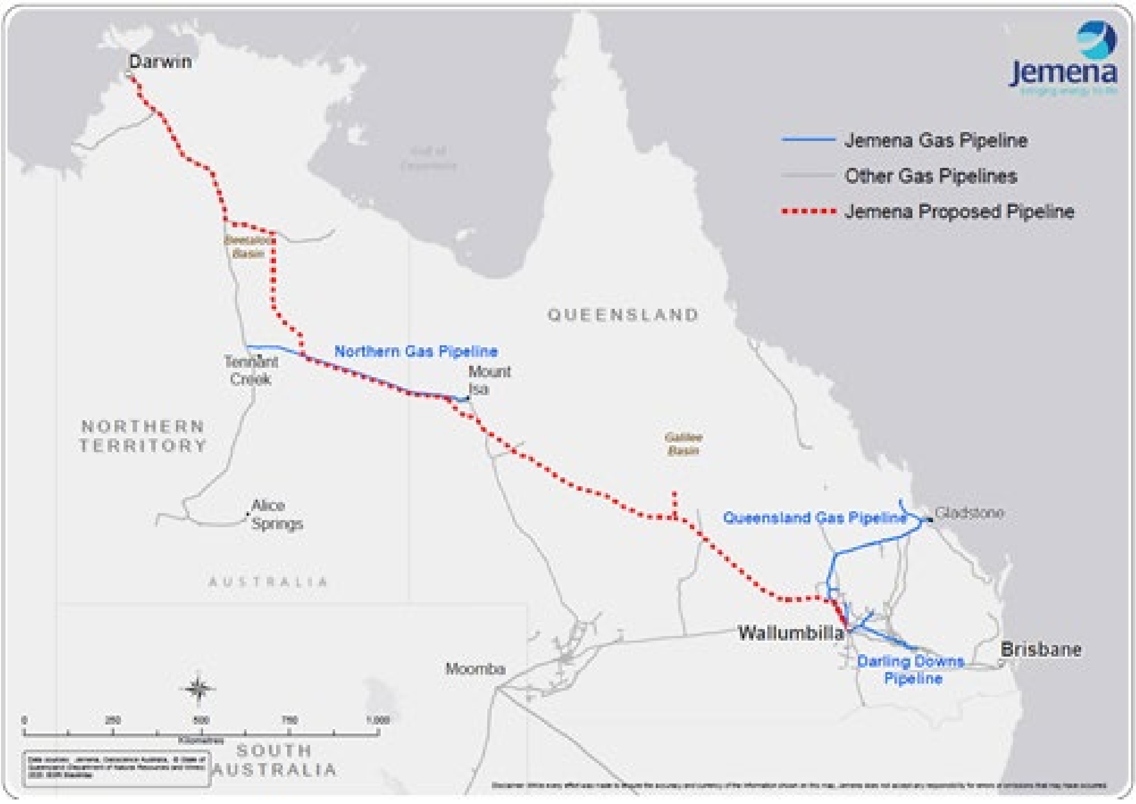
Gas Infrastructure: Jemena JV to Connect Beetaloo to SE Australian Gas Market

TBN's EP136 development is underpinned by its new joint venture (JV) with Jemena to build, own, and operate the long-term midstream gas infrastructure. The memorandum of understanding (MOU) was executed in May 2020, giving exclusivity to TBN. The JV will see Jemena invest up to $5bn to construct an initial pipeline connecting the Beetaloo Basin production directly to the south east Australian domestic gas market via its existing Northern Gas Pipeline (NGP).

The first stage will double the capacity of the NGP to approximately 200 TJ/day by 2025 before further expansion to 1,000 TJ/day in 2028+. This will be through a combination of compression and looping, while also working to extend the NGP from the Beetaloo Basin to the Wallumbilla Gas Hub in Queensland.

This joint venture to construct the initial pipeline is evidence of collaboration for the industry and gives TBN a first-mover advantage as well as another avenue of optionality to participate in the economics. TBN has the strategic ability to invest alongside Jemena into the pipeline, while it is not obliged to do so; we believe TBN would only consider such an investment in 2025 or later when it has first gas from EP136.

Exhibit 5 – Jemena pipeline



Source: Jemena.

Exploration: About to Kick Off – Watch This Space

EP161 (25% interest)

Discovery drilling so far has achieved higher-than-expected flow rates

The Tanumbirini #1 discovery well was initially drilled in 2014 to 500m, finding high-quality Mid-Velkerri shale after Santos completed a 500km 2D seismic survey (see next section for a description of the geology of the area). A 90m core was taken and extensive wireline and core evaluation conducted.

During 4Q 2019, Santos successfully completed a 4-stage vertical frac stimulation program over the full shale section in the Mid-Velkerri (A/B/C). The well is one of the deepest onshore wells to have been drilled in Australia, reaching a total depth of 3,945m.

During 1Q 2020, the 129-day flow test hit max production of 1.6 mmcf/d and averaged at 400 mcf/d with no decline. The flow test was ended prematurely in April 2020 due to shut in because of COVID-19. After being shut in for over 160 days, the well was reopened in October 2020 and initially flowed at 10 mcf/d and achieved an average flow rate of 2.3 mmcf/d during the first 90 hours of testing, ahead of expectations. This suggests that the quality (thickness, porosity and resulting gas in place [GIP]) of the Mid-Velkerri B is higher at Tanumbirini #1 than at Origin/Falcon's Amungee NW-1H location.

Upcoming drilling: 2 horizontal wells in FY2022; more later, if successful

Santos is now drilling two horizontal wells, Tanumbirini #2H and Tanumbirini #3H, including an aggregate 180-day flow test, in the Mid-Velkerri formation during FY2022. Santos expects initial flow test results from both wells 4Q CY2021.

- Tanumbirini #2H will drill up to 4,800m lateral targeting the B shale with 10-20 frac stimulations followed by a 90-day flow test. The drilling was initially delayed from late 2019 due to a mechanical issue/over run at Santos' Dukas site (where it was using that same rig) and then in early 2020 due to COVID-19. Drilling commenced on 11 May 2021

and they have completed drilling the vertical hole and build section at 3,800m. Santos expects to reach 4,800m by the end of July 2021.
- Tanumbirini #3H will drill up to 4,800m lateral targeting the Lower B shale with 10-20 frac stimulations followed by a 90-day flow test. This will commence on completion of Tanumbirini #2H, utilising the same rig.

Dependent upon the success of these wells, the JV may drill two follow-up horizontal wells, Inacumba #1H and #2H, and associated flow tests. The next step would be to initiate plans to commercialise the licence's gas resources with additional drilling to further de-risk the development.

Santos' stated view on EP161 and the Basin

- Santos is supportive of both the Basin and the resource. Stating that the Basin could provide the same positive impact to Australia as the shale gas revolution has done for America. While the resource has potential to feed gas to support future backfill and/or expansion opportunities through Darwin LNG.

EP136 (100% interest)

2D seismic: CY2021

TBN plans to start with a 2D seismic survey to support drill site selection for the initial well in 1HFY22.

Spud to confirm deliverability of Mid-Velkerri: CY2022

TBN targets spudding the Maverick #1 horizontal well to confirm potential deliverability of the Mid-Velkerri in CY2022. This is expected to be up to 2,000m lateral targeting the B shale with 35 frac stimulations followed by a 180-day flow test. Management's knowledge and experience supports the greater intensity of this well.

3 potential additional wells and flow tests: CY2023

Assuming success of this well, management expects to drill up to three additional horizontal wells (pad drilling) and associated flow tests in CY2023. The aim is to get to sanction point for the pilot program at the end of this drilling, which should come with an initial 2P reserve booking and long-term domestic gas offtake agreement. Over CY24/25, TBN expects to work with Jemena on an infrastructure solution to enable a cheaper commercial pathway for the gas. This timing is consistent with Jemena's public statements.

The key point on the drilling program is operator knowledge and experience. Given the strong alignment with Santos on EP161, this will enable technical and operational planning, including coordination of potential rig- and equipment-sharing options across both EP161 and EP136. Management's experience in North America derisks TBN's lack of operator experience to date.

End-Market Optionality

Location and working relationships give TBN good options for end markets

The location of Beetaloo gives TBN optionality to send gas north to LNG plants or south east to LNG plants or the domestic gas market.

Furthermore, TBN's working relationships provide options regarding where its gas ends up through:

- its MOU with Jemena giving TBN first-mover advantage to take gas to the domestic south east gas markets
- its joint ownership in EP161 alongside Santos, which is owner/operator of two existing LNG plants for LNG backfill. Santos owns 43% of Darwin LNG, 30% of Gladstone LNG (GLNG) and is operator of both plants.

Our expectations on end markets

We assume EP136 goes to domestic gas markets, while EP161 heads to the Asian LNG market (see Exhibit 6).

Exhibit 6 – Our end-market assumptions

Product	**Approx. volume and timing**	**Transport**	**End market**
Initial gas from testing wells at EP136	15+ PJ/y (40 mmcf/d) in FY2024	Existing pipelines	NT local gas markets: • spot initially • then under long-term contracts with NT users
Pilot program at EP136	40 PJ/y (100 mmcf/d) in FY2025	Existing pipelines	Southeast domestic gas markets via secure long-term gas offtake arrangements
Full field development at EP136* or EP161 **assumes 100% interest in EP136*	200 PJ/y (500 mmcf/d) in FY2028+	New Jemena pipelines	Darwin or Gladstone (LNG backfill)

Source: MST Access.

Asset Context: A Closer Look at the Beetaloo Basin – Geology and Policy

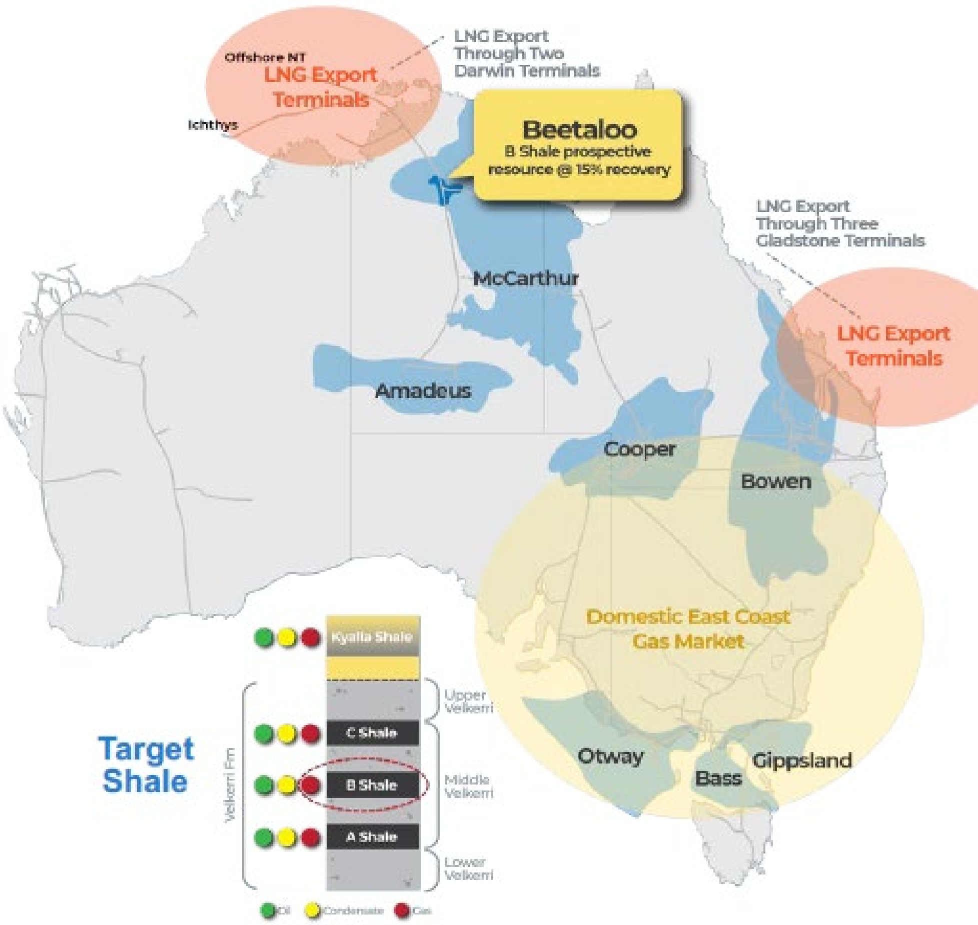
Understanding the Beetaloo Basin: The Land and the History

The Beetaloo Basin is located in the Northern Territory (NT), ~500km south east of Darwin, and covers a remote, sparsely populated area of 6.9m acres. Its proximity to Darwin, a major industrial and LNG export market, provides relative logistical and operational benefits. The basin is of Proterozoic age (1.4bn years old) and holds unconventional shale oil and gas.

The Beetaloo is one of the deepest in the region, reaching basin-centre thicknesses greater than 3,000 m. It is split up into three areas – the core, the extension and the shallow – reducing in thickness and quality as you move out from the core. The primary target in the basin is the Mid-Velkerri "B" shale, which is an extensive dry gas resource estimated to have up to 75 Tcf of recoverable resource.

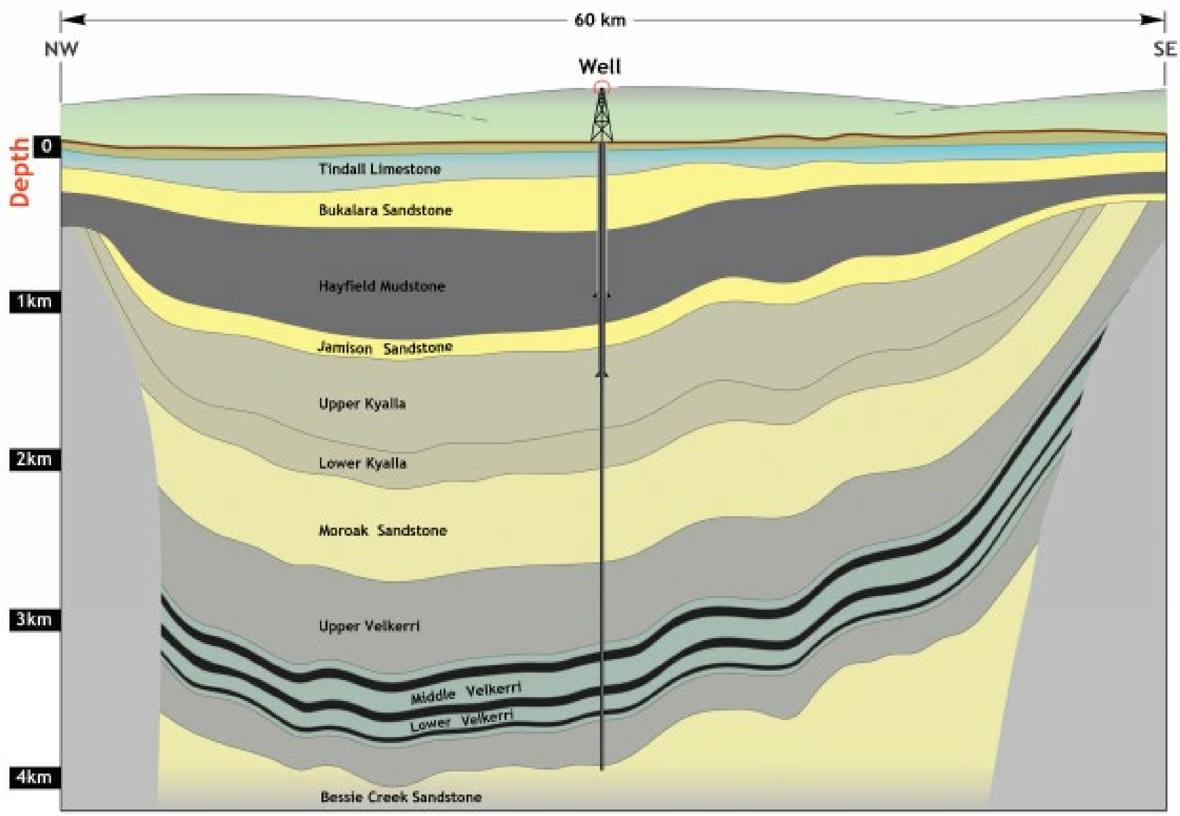
Exploration began in the basin for conventional oil in the 1960s. Corporate activity increased in the early 2010s on the back of successful shale exploration and learnings in the US. A positive sign for unconventional gas was the difficulty of getting out conventional gas, supporting the view that the gas is trapped in tighter shale rocks. There has been no commercial gas production to date.

Exhibit 7 – Location of the Beetaloo Basin



Source: TBN.

Exhibit 8 – Depth: cross-section of Beetaloo Basin



Source: Origin.

Parallels of Beetaloo to US Marcellus: Some Australian Advantages to Benefit TBN

Beetaloo has superior reservoir thickness, mineralogical properties, gas in place concentration

It has been proposed that the area has similar properties to the US Marcellus shale, currently the most prolific unconventional gas shale play in North America. However, the Beetaloo has some advantages over Marcellus due to:

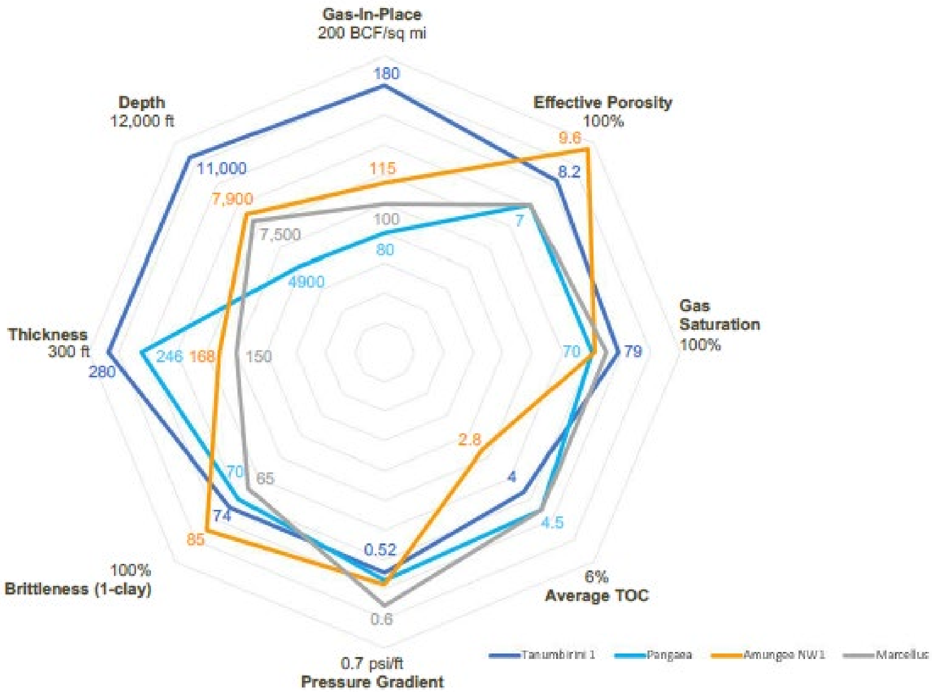
- reservoir thickness and permeabilities
- mineralogical properties to allow fracturing (frac) stimulation
- high gas in place (GIP) concentration. The Marcellus has GIP average of 100 Bcf/square mile (and up to 150 Bcf/square mile), while Beetaloo's Mid-Velkerri B and C shale GIP has 150–200 Bcf/square mile based on petrophysical analysis.

TBN can leverage its experience to obtain the maximum benefit from these advantages

Based on these advantages, it is expected that a core Beetaloo Mid-Velkerri B typical horizontal well of 2,500m with 300m drainage width and 50% gas recovery rate can provide 29 Bcf gas recovery: a 28.5X greater recovery than Santos' Cooper Basin portfolio in FY2020.

This is where TBN can add a point of difference. TBN's management's first-hand experience with North American shale gas can be extrapolated to its own acreage in the Beetaloo. It took the US shale industry a few years to become efficient at drilling, exploration and technology application, before advancing its knowledge and experience with horizontal drilling and more frac stages (portion of the horizontal section of the well that is being fraced) over the following 3–4 years. From there it was all about gaining scale. While the Beetaloo is only at the start of its journey, say 2008 if you compare it back to the US, TBN management have the experience required to apply 2015 US shale technology.

Exhibit 9 – Comparison of geological attributes



Source: Tamboran.

Exhibit 10 – Comparison of Beetaloo with US basins

	Marcellus Shale[1]	Barnett Shale[1]	Middle Velkerri Shale
Estimated Basin Area (km^2)	246,050	12,950	17,070[4]
Typical Depth (m)	1,220-2,590	1,980-2,590	1,000-2,500
Gross Thickness (m)	60	60-305	45- >420
Net Thickness (m)	15-105 (45)	30-215 (90)	60-86 (73)[2]
Reported Gas Contents (scf/ton)	60-150	300-350	100[2]
Porosity (%)	4-12 (6.2)	4-6 (5)	2-8
Gas-filled Porosity (%)	4	5	2.5[2]
Water Saturation (%)	43	38	58[2]
Permeability Range (average) (nD)	0-70 (20)	0-100 (50)	10-100 (50)
Reported Silica Content (%)	37	45	49 (1-77)
% Ro (average range)	1.5 (0.9-5)	1.6(0.85-2.1)	1.5->2.5[3]
TOC present-day (average in wt%)	4.01 (2-13)	3.74 (3-12)	3.74 (1-10)

Source: Falcon Oil & Gas. *TOC: Total organic carbon.*

Beetaloo Exploration to Date Is De-risking the Area

Drilling to date has de-risked Mid-Velkerri B

Beetaloo Basin has seen $350m capital spent to date, largely through Origin/Falcon's capex program. Most of this has been on vertical wells, seismic and an initial horizontal well drilled by Origin in 2016. Amungee NW-1H was drilled in 2016 with 11 fractionation stimulation stages over 1,000m and with only 60% of the horizontal length stimulated. On a 60-day flow test, the well averaged 1.1 mmcf/d. The average cost of wells has come in around $24m. This drilling significantly de-risked the Mid-Velkerri B for the area. In February 2017 Origin/Falcon 'declared a discovery' of 6.6 Tcf gross. EP76 lies directly next to EP136 and EP161.

Based on this outcome, modelling is for production potential of 10-15+ mmcf/d and 15-20+ Bcf/well recoveries from 2,000m horizontal wells in the EP161/EP136 area.

Further de-risking continues with current drilling in the area

Origin/Falcon's EP76 is expecting additional drilling over 2021–22 including a vertical well at Velkerri 76. Also, Empire Energy's EP187, on the eastern fringe of the Beetaloo, is currently drilling a vertical well with four frac stages and associated flow tests at Carpentaria #1.

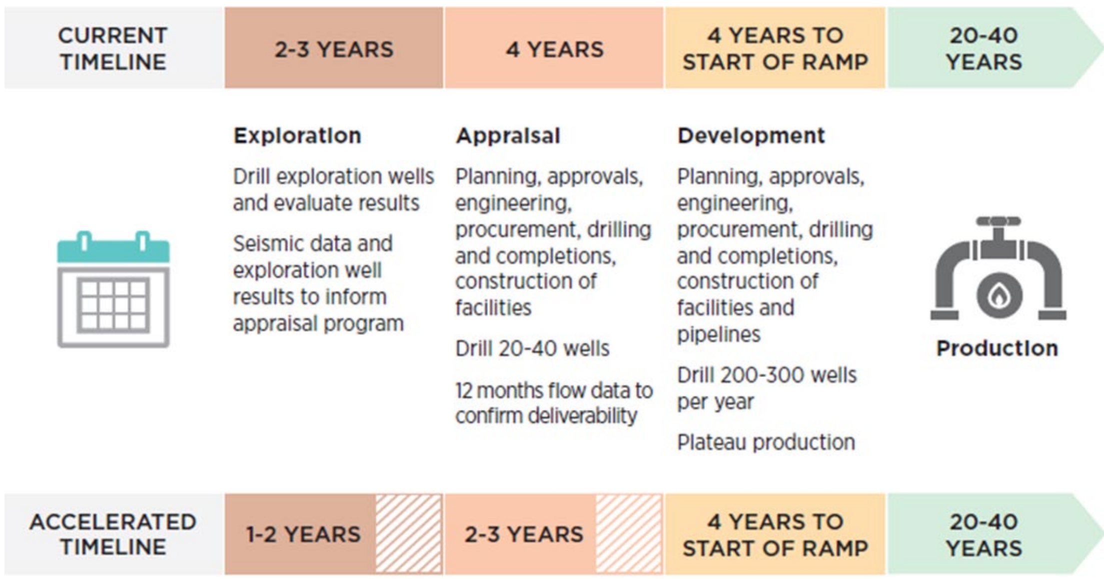
Federal Government Focused on Support

The government sees gas as an ideal transitional fuel, acknowledging the intermittent nature of current renewable technology while reducing the nation's carbon footprint, and the policy is focused on developing gas resources.

The Federal Government has identified the Beetaloo Basin as a priority development to address domestic gas shortfalls by 2024. The Beetaloo Strategic Plan involves investment of approximately $220m with actions across the following areas:

- building a clear picture of the Beetaloo through exploration and identifying the resource
- regulating efficiently and effectively through environmental research and assessments
- enabling infrastructure through public road funding, midstream pipelines and project financing
- sharing regional benefits through Indigenous support.

Exhibit 11 – Expected impact of the Beetaloo Strategic Basin Plan on the timing of Beetaloo gas development



Source: Federal Government.

In December 2020, the Government announced $50m in incentives under the Beetaloo Cooperative Drilling Program to support $200m of exploration activity by the end of June 2022. This aims to fast-track exploration with grants of $7.5m per well, capped at 25% of eligible exploration costs and three wells per venture. Last week, Empire Energy (EEG-ASX) was the first company to have received approvals for grant funding of $21m. Other initiatives include enabling key infrastructure projects such as pipelines and assisting with infrastructure financing. Currently there is real work being done on the roads to improve all-weather access.

Overall, the strategic plan aims to accelerate the development stages for final investment decisions by 2025 or earlier. Without the plan, current industry analysis to date suggests exploration would be finalised by 2023 before the appraisal stages occur over another four years, which would mean investment decisions are potentially not made until around 2027.

This is in addition to the Federal Government's 'gas-led recovery' initiative to come out of COVID-19 in September 2020, with the aim of giving multiple options for gas to help with economic growth. The focus is on getting more supply by developing out the basins, setting targets and improving infrastructure, along with ensuring this all happens at a reasonable price for domestic gas through a prospective gas reservation scheme.

Board and Management: Pertinent Experience

TBN's management team and board feature a blend of North American and Australian oil and gas industry veterans with a heavy skew to expertise in shale plays and early-stage E&P development. For a company this size, the board is reasonably large with seven members.

Board and Management Profiles

Dick Stoneburner – Non-Executive Chairman. Mr Stoneburner has a background in energy/geology. He is currently Executive Adviser at Pine Brook Partners. Formerly, he was founder, President and COO of US listed shale gas company, Petrohawk (2003–2011). Petrohawk was acquired by BHP in 2011 for EV = US$4.44/trillion cubic feet of natural gas equivalent (Tcfe) over 3.4 Tcfe of proved reserves (=A$4.17/Tcfe) in the Haynesville and Eagle Ford. He held earlier positions at Texas Oil and Gas, W/E Energy, Hugoton Energy and 3TEC Energy.

Joel Riddle – Managing Director and Chief Executive Officer. Mr Riddle has a background in energy. He is former Vice President, Commercial and Planning of NYSE-listed deepwater energy company, Cobalt International (2006–2013). He also has technical and leadership experience at Exxon Mobil, Unocal, Chevron and Murphy Oil.

Patrick Elliott – Non-Executive Director. Mr Elliott has a background in energy. He is founder of TBN and former founder and director of Australian-listed energy company Eastern Star Gas and SAPEX Ltd. Eastern Star Gas was taken out by Santos and TRUenergy in 2011 at a 3P reserve multiple of $0.50/GJ for gas assets in Central NSW. SAPEX was acquired by Linc Energy in 2008 for gas assets in South Australia. Mr Elliott was also the former Chairman of Meerkat Energy and MD at Gold Fields Morgan Grenfell.

Ann Diamant – Non-Executive Director. Ms Diamant has a background in energy/as an equities analyst. She is well known to the Australian energy market through her Investor Relations and Communications role at Oil Search, along with Orogen Minerals.

Fred Barrett – Non-Executive Director. Mr Barrett has a background in energy. He is former Founder, Chairman, CEO and President of US Rocky Mountain oil and gas play, Bill Barrett Corp (2002–2013). Bill Barrett merged with Fifth Creek Energy in 2017 to become HighPoint Resources. He held earlier positions at The Williams Companies, Barrett Resources and Teared Oil.

David Siegal – Non-Executive Director. Mr Siegal has a background in aerospace/aviation. He was appointed through TBN's transaction with Longview/SweetPea. He is currently Senior Advisor to Apollo Global Management and Chairman of two Apollo portfolio companies. He was formerly CEO at the following: aircraft leasing company AWAS, Frontier Airlines, XOJET, Gategroup, US Airways Group, Avis Budget Group and Continental Express Airlines.

Dan Chandra – Non-Executive Director. Mr Chandra has a background in finance. He is currently an investment professional at Lion Point Capital. He was formerly a senior analyst and PM at DW Partners/Brevan Howard.

Board and Management Share Ownership

Management and the Board currently own 10% of the stock on a fully diluted basis (6% undiluted). Management's KPIs only come from the performance of the share price with 'milestone' options vesting if the share price hits $1.00, $1.50, $2.00 and $2.50, ahead of May 2026. Management shares are in escrow for 24 months.

Industry: Under-Supplied Macro Picture

The story of the lack of natural domestic gas supply to the east coast of Australia is well known – limited production with constrained pipeline capacity teamed with additional demand from the LNG plants. The Beetaloo Basin could potentially make a major contribution to resolving this problem and assisting the post-COVID economic recovery. The Federal Government is all over this, hoping to expedite additional gas while creating 4,000 jobs.

The ACCC's recent Gas Inquiry forecast a potential domestic gas supply shortfall of 30 PJ pa as early as 2024 before a much greater potential shortfall of 358 PJ pa in 2032. This is in addition to the 100 PJ pa shortfall for east coast LNG.

Supply is Easier to Forecast than Demand – and Supply Appears Limited

- Declining production in Queensland (QLD): Drilling of CSG for LNG is coming out of the ground at higher rates of decline than originally forecast, and this is unlikely to change unless new sources of gas are discovered. Furthermore, given lower gas prices recently, producers are now projecting a slower development schedule.
- Declining production in Victoria (VIC): VIC's previous excess production of gas that found a home in the other States of Tasmania, New South Wales (NSW) and South Australia (SA) will decline if no new reserves or resources are developed, which means customers will need to source more gas from the northern states/territories.
- Pipeline constraints: Will limit the amount of supply that can go south.

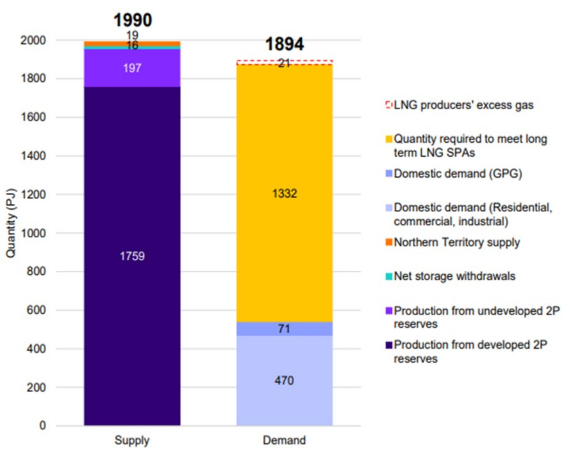
Offsetting this is the development by Andrew Forrest through the Australian Industrial Energy's (AIE's) commitment to the Port Kembla Gas Terminal (PKGT) in NSW. The LNG import terminal is estimated to inject up to 500 TJ/d into the domestic market, namely NSW and VIC, to aid with extreme winter electricity peaks against the declining VIC production. First gas is expected in 2023. Of course, this development comes with risks, particularly on timing.

While new gas supplies will help improve the adequacy of supply, they are likely to be more costly than existing production given the cost to discover and develop them.

Demand Is Broadly Supportive

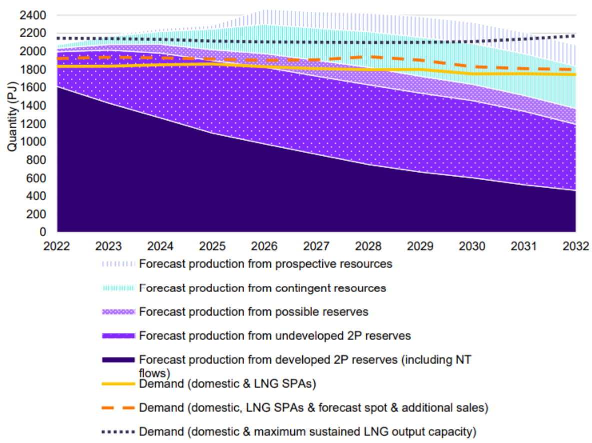
Demand is largely driven by long-term LNG contracts, with export demand the incremental swing factor. Declining CSG production will help support this demand along with undersupplied global markets. Domestic demand through residential, commercial and industrial consumption has remained reasonably consistent and according to AEMO forecasts is expected to remain so. The focus on renewables, while targeted to be a negative impact to gas demand longer term, will result in a more 'peaky' gas demand profile with greater value placed on flexible supplies.

Exhibit 12 – 2021: east coast gas supply/demand



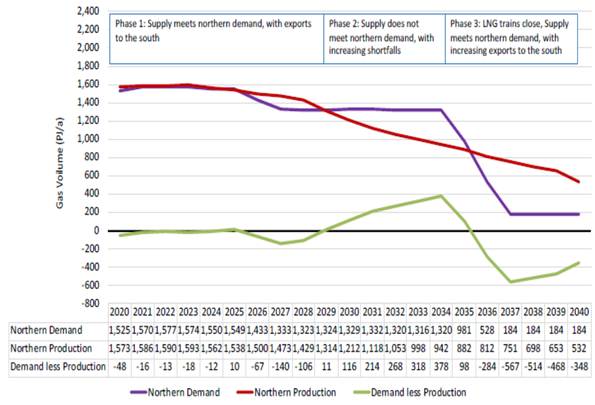
Source: ACCC Gas Inquiry 2021.

Exhibit 13 – 2022–2032: east coast gas supply/demand



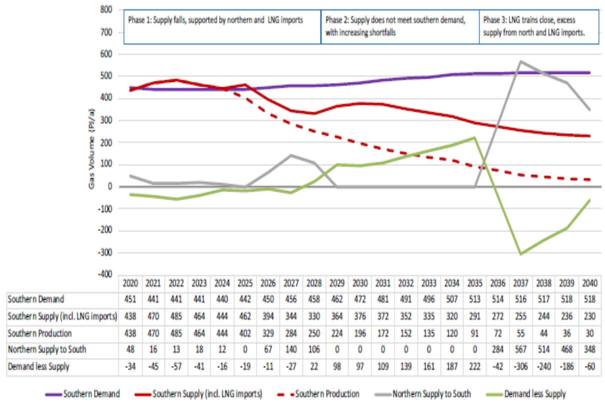
Source: ACCC Gas Inquiry 2021.

Exhibit 14 – Northern Region demand and supply



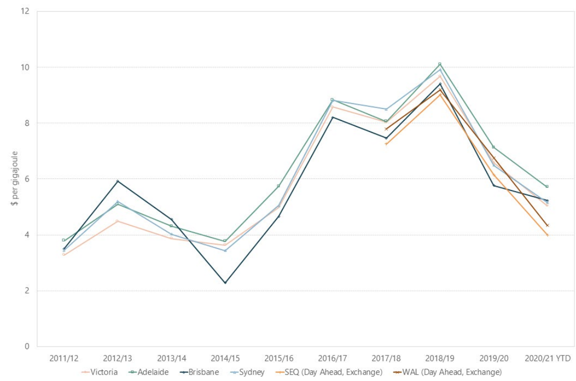
Source: EnergyQuest.

Exhibit 15 – Southern Region demand and supply



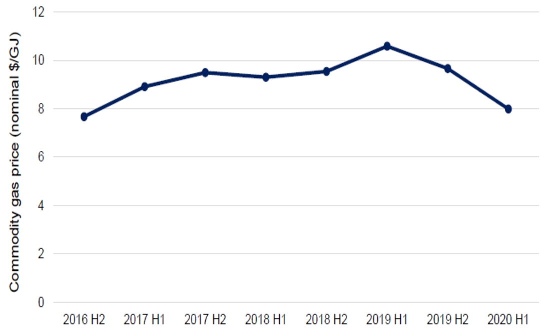
Source: EnergyQuest.

Exhibit 16 – Spot domestic gas prices



Source: AER.

Exhibit 17 – Contracted domestic gas prices

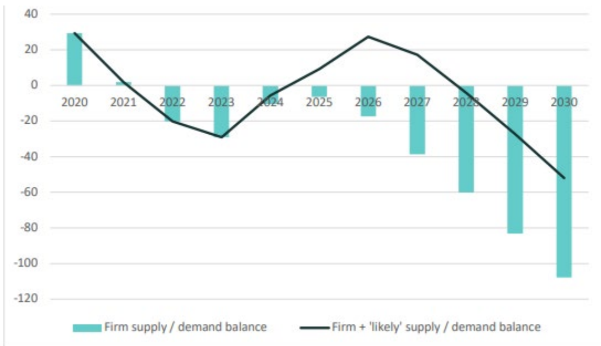


Source: ACCC Gas Inquiry 2021.

Global LNG Markets Likely to Remain Undersupplied

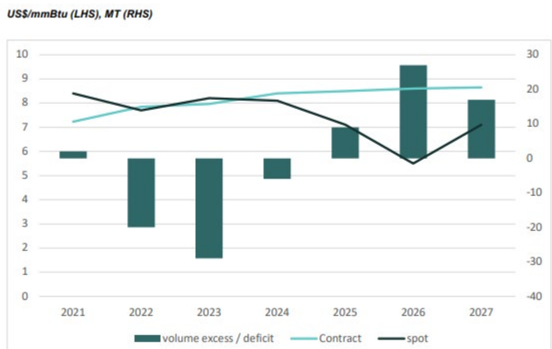
Global LNG markets remain supply constrained from new projects not meeting economic return hurdles in the face of continuing demand. MST's Global LNG specialist, David Hewitt, expects the global LNG market to be in undersupply near term and oversupply from 2025+. But as history has shown, supply typically comes in under expectations given the huge size, cost and coordination these projects require – so an undersupplied market is likely to hold for longer.

Exhibit 18 – LNG supply/demand



Source: MST Marquee.

Exhibit 19 – LNG supply/demand and price



Source: MST Marquee.

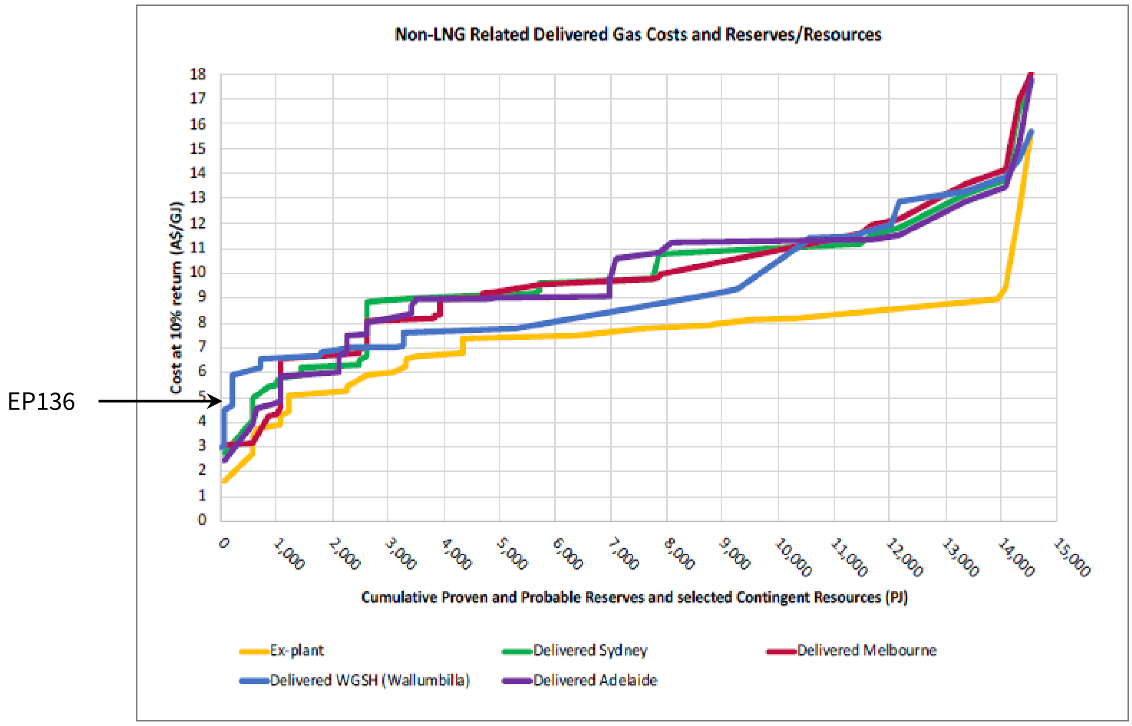
Financials: Focus on Costs + Funding; Exploration to Kick Off Shortly

With the recent IPO raising, TBN should be fully funded for the initial three drilling wells and associated costs, covering the next 12-18 months. The $140m funding gap to our expectation for FCF positive in FY26 can be met through existing funds, option funding, government grants, assets sales, farm downs or further tapping the equity market.

Upstream and production costs to trend down by FY2028

Key to the success of any project is for it to be as low as possible on the cost curve. Given management's experience, the EP136 Maverick pilot development should see it deliver a project in the south east Australian domestic gas and LNG market, putting it towards the lower end of the cost curve. Management expects the upstream costs to trend down towards $3/GJ by 2028 with an all-in cost to LNG fields of $3.50-5.00 as it benefits from the new Jemena pipeline.

Exhibit 20 – Non-LNG–related delivered gas costs and reserves/resources (A$/GJ)



Source: EnergyQuest.

Exhibit 21 – Estimated cost breakdown: production costs + pipeline costs

		To NT		To SE Aust with existing pipeline		To Darwin LNG Backfill		To Gladstone LNG Backfill	
		2023-24		2025		2028+		2028+	
Production Costs	/GJ	$	4.50	$	3.25	$	3.00	$	3.00
To NT. Via McArthur River Pipeline	/GJ	$	0.50						
To SE Domestic Gas. Via existing pipeline	/GJ			$	4.00				
To Darwin LNG. Via new Jemena pipeline	/GJ					$	0.50		
To Wallumbilla. Via new Jemena pipeline	/GJ							$	2.00
Cost	**/GJ**	**$**	**5.00**	**$**	**7.25**	**$**	**3.50**	**$**	**5.00**

Source: MST Access.

Drilling costs: we assume experience and scale will drive costs down

Drilling costs traditionally run a downward trajectory: initially through commitment and cost leverage, and in the second stage through well experience.

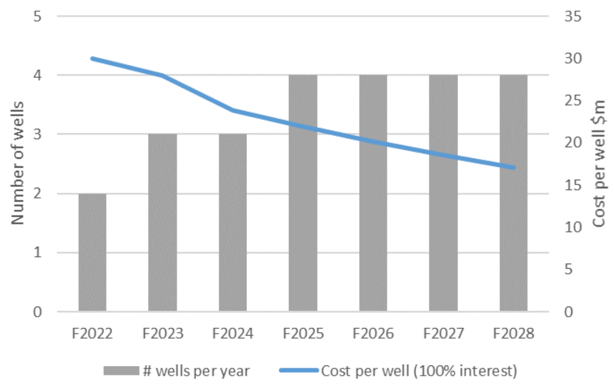
We assume that gross drilling costs at EP136 start out at $40-45m per well. After 18 months and experience with 3–5 wells, this should get down to around $25-30m through rig utilisation and fixed-cost leverage. Through further scale and learnings, this should come down to $20m/well in FY27/28+. We assume costs are ~$5m per well lower at EP161 given it is further advanced.

Exhibit 22 – Assumed cost of drilling program

		EP161		EP136		
		CY2021	CY2022	CY2021	CY2022	CY2023
# wells	#	2	2	0	1	3
Cost to TBN (prospectus)	$m	16.8	25.1	16.8	60.0	130.0
Est. gross cost/well $m	$m	30.0	28.0	8.0	45.0	34.0
Est. other costs	$m	1.8	11.1	8.8	15.0	28.0

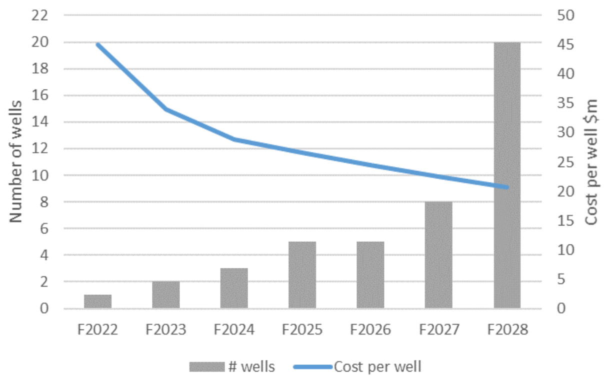
Source: MST Access.

Exhibit 23 – EP161 drilling



Source: MST Access.

Exhibit 24 – EP136 drilling



Source: MST Access.

US and Australian examples show how costs can fall over time as production increases

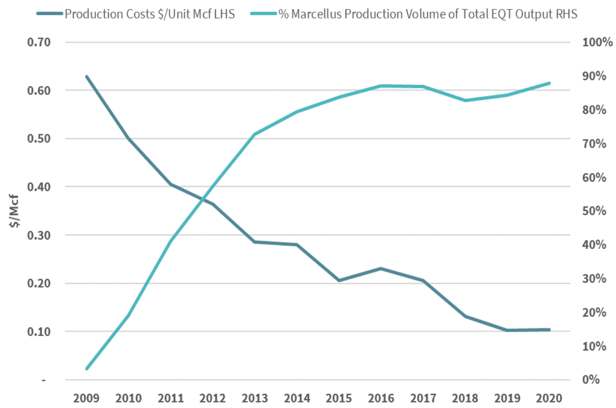
Looking at two examples for costs: projects in the US Marcellus and the Australian Cooper Basin have both experienced cost reductions of about 15% pa in the early years, sliding out to 10% pa.

US (Marcellus) example: EQT Corporation

- 2008–2010: production costs dropped 27% pa, while production went up 27% pa.
- 2010–2013: production costs consistently fell 17% pa, while production volume increased 41% pa.
- 2014–2019: production costs fell an average of 8% pa, while production volume increased 24% pa. (These later years were less consistent.)

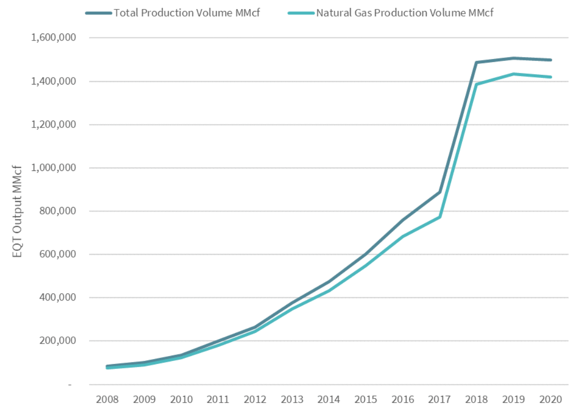
We calculate a 77% correlation between scale and cost benefit.

Exhibit 25 – EQT: production costs and % Marcellus



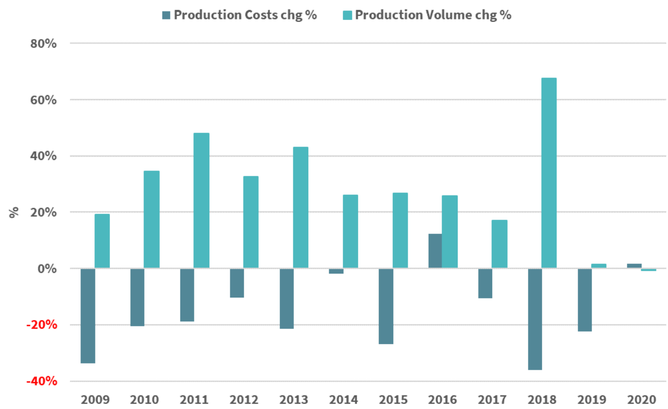
Source: MST Access.

Exhibit 26 – EQT: production volume



Source: MST Access.

Exhibit 27 – EQT: production costs and volume change



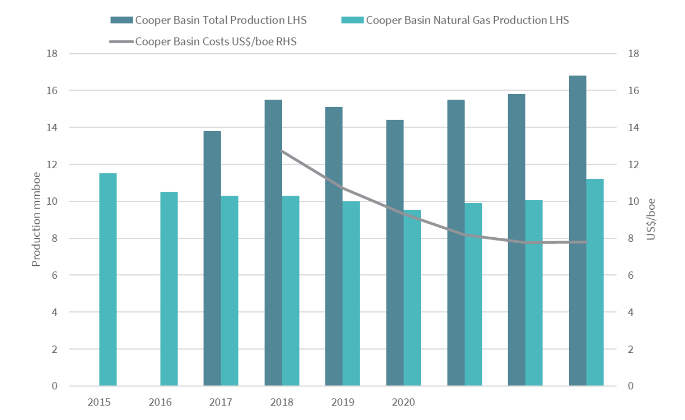
Source: MST Access.

Australian (Cooper) example: Santos

Using Santos for an Australian example, the outcome is more pronounced.

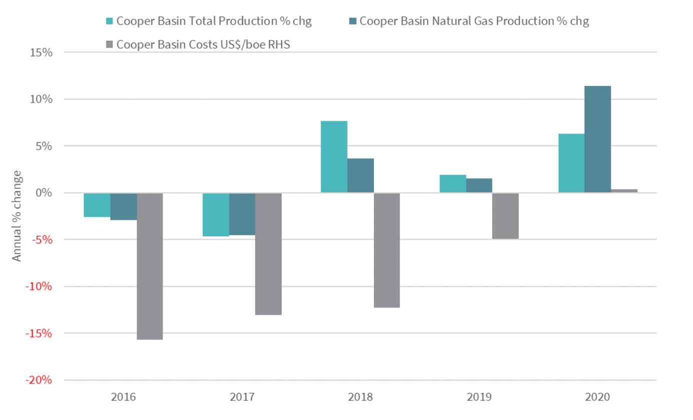
- During the earlier years (2015–2017), commitment and cost leverage saw production costs improve by 14% pa (some of this was stripping out costs on the back of a weaker macro environment).
- The following two years, costs came back 9% pa while production increased 5% pa, seeing the scale benefit.

Exhibit 28 – Santos: production costs and volume



Source: MST Access.

Exhibit 29 – Santos: production costs and volume



Source: MST Access.

Production may also benefit from TBN's experience with longer laterals for higher intensity frac stimulations

Another factor potentially contributing to the production benefits for the Marcellus is the style of completion. North American drilling typically has longer laterals and more sections in the laterals to give it higher intensity on the frac job as a result. TBN management have this experience to bring to EP136 drilling, hence the planned 2,000m lateral with 35 frac stimulations at Maverick #1 and the Santos operated EP161 Tanumbirini #2H/#3H up to 4,800m lateral with 10–20 frac stimulations.

Looking at some North American examples:

- EQT in 2020 completed drilling of an average lateral of 3,650m with 13 frac stimulations.
- Range Resources in 2019 completed drilling of an average lateral of 3,400m.

Funding: Funding optionality

Funding adequate for next 12–18 months

TBN had been funded to the end of April 2021 by raising a total of ~$86m from existing private investors. The recent IPO brought in additional net proceeds of $56m, bringing cash levels up to $67m. Management expects current funding to cover the drilling of three wells (EP161 $28m/well gross, EP136 $40m) and seismic ($8m), plus costs. We are assuming slightly higher costs at EP136, but existing funding should cover 12–18 months on our estimates.

With Empire Energy (EEG-ASX) having received $21m of government grant funding for the development of the Beetaloo, we assume TBN should receive similar funding. We assume TBN should receive this over FY22/23.

Funding optionality–farm downs, sale, equity raising

Assuming TBN can begin to get revenue off the local NT gas market in FY23, we estimate that TBN will be FCF positive by FY26. Ahead of this, our estimated funding requirements through to the end of FY25 are ~$416m, vs earnings of ~$260m, leaving a shortfall of ~$156m. Exhibit 30 shows our estimates for the shortfall. We do not assume the Employee Milestone Options are met and as such only $6.1m of the full $12.5m option funding will come through.

Exhibit 30 – Funding Shortfall

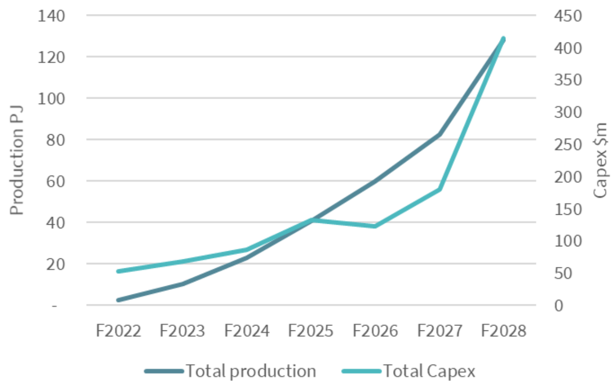
		Shortfall $m
		-156.5
Existing cash $m	10.8	-145.7
IPO raising $m	61.0	-84.6
Option funds $m	6.1	-78.6
Government grants	21.0	-57.6
Additional funds	75.0	17.4

Source: MST Access.

The additional funds can be sourced through various options, including asset farm downs from EP136 (currently 100% interest), the sale of EP161 (currently 25% interest); and/or through tapping the equity market (assuming that is open to TBN). We assume an additional $55m of capital is raised in FY23 and a further $20m in FY25.

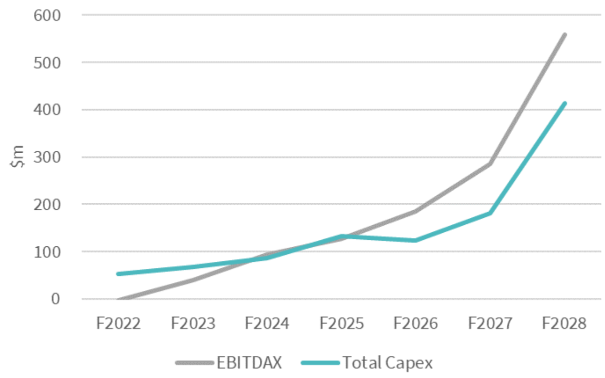
TBN currently has no debt and no debt facilities.

Exhibit 31 – TBN: production vs capex



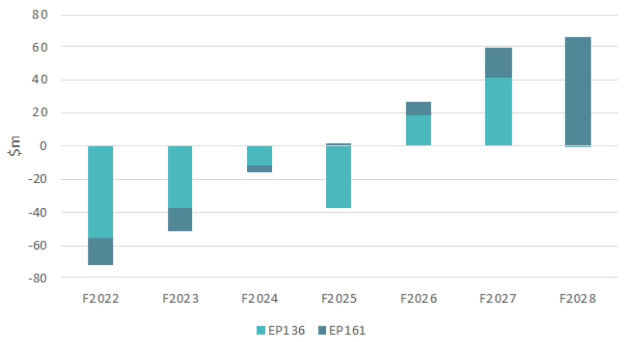
Source: MST Access.

Exhibit 32 – TBN: EBITDAX vs capex



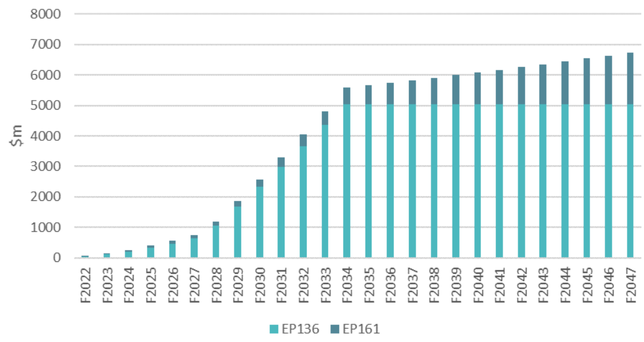
Source: MST Access.

Exhibit 33 – TBN: FCF positive by FY2026



Source: MST Access.

Exhibit 34 – TBN: cumulative capex



Source: MST Access.

Key investors - post listing

- Longview 21.9%
- The Baupost Group 20.6%
- Lion Point 10.7%
- Venture Holdings 5.2% (Investment associated with the H&M Family)
- Geotech Investments 5.1% (Investment associated with Paul Fudge)
- Board and Management 6.1%, increasing to 10.2% of fully diluted basis

These investors contributed an additional $8.8m to the recent IPO raising of $61m.

Management and Board shares including LongView holdings are in escrow for 24 months. Baupost and Lion Point, who account for 30.6% on undiluted holdings, have voluntarily escrowed their shares for 6 months.

Valuation: What It's Worth – Risk-Adjusted DCF of $0.61

Risk-Adjusted DCF, Driven Largely by EP161

Our per-share valuation for TBN is $0.61, which we view as a reasonable base case. We also outline a more optimistic 'high' case and a more conservative 'low' case based on discount rate in Exhibit 35, along with the overall DCF calculation.

We value each of the company's assets using a risk-adjusted DCF (see Exhibit 36), modified for the corporate overhead liability, net cash, funding from future options and government funding to get a 'going concern' valuation for the group. As with all valuations, in particular for energy companies, there are a lot of assumptions. We have complemented this with sensitivities to give a more rounded view.

The key driver of our valuation longer term is EP161, given its greater expected gas resource and the likelihood of feeding gas into its JV partner's LNG facilities (see Exhibit 36).

Our CAPM assumptions are outlined in Exhibit 38.

Exhibit 35 - Company valuation

VALUATION		FY22	Low	Base	High
Discount rate used in NPV calculations			12.0%	9.6%	8.0%
EP161 25%, risked at 15%	$m		156	224	287
EP136 100%, risked at 10%	$m		138	179	212
Assets	**$m**		**294**	**403**	**499**
Site Restoration	$m		-15	-15	-15
Corporate Costs Allocation	$m		-58	-70	-79
Enterprise Value	**$m**		**221**	**318**	**404**
Net Debt / (Cash)	$m		67	67	67
Government Funding	$m		21	21	21
Options	$m		12	12	12
Equity	**$m**		**321**	**419**	**505**
Diluted Shares on Issue	m		690	690	690
Per Share	**$**		**0.47**	**0.61**	**0.73**
Share price return	%		29%	69%	103%
Dividend Yield	%		0%	0%	0%
Total Shareholder Return	**%**		**29%**	**69%**	**103%**

Source: MST Access.

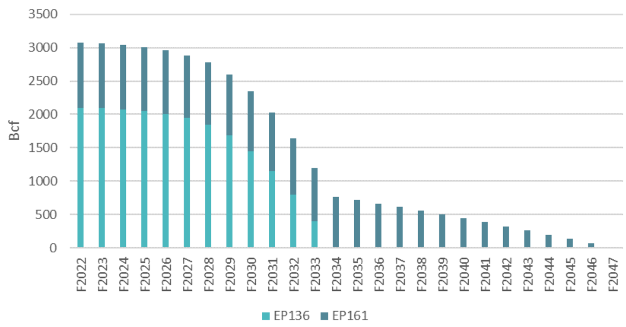
Exhibit 36 – Asset valuation

EP161 (25% Interest)		FY22	FY23	FY24	FY25	FY26
Gas production	PJ	0.8	2.7	5.0	7.3	9.7
Price realised	/GJ	$ -	$ 8.50	$ 9.00	$ 9.50	$ 9.60
Operating costs	/GJ	-$ 1.33	-$ 6.12	-$ 6.33	-$ 6.50	-$ 6.65
Net price	/GJ	-$ 1.33	$ 2.38	$ 2.67	$ 3.00	$ 2.94
Revenue	$m	0	23	45	69	93
Operating costs	$m	-1	-17	-32	-48	-65
EBITDAX	$m	-1	7	13	22	29
Capex	$m	-15	-21	-18	-22	-20
Tax	$m	0	0	0	0	0
FCF	$m	-16	-14	-4	0	8
Discount Rate	%	9.6%				
NPV	$m	1,492	1,507	1,519	1,523	1,523
Risked	%	15%				
Risked NPV	$m	224	226	228	228	228

EP136 (100% Interest)		FY22	FY23	FY24	FY25	FY26
Gas production	PJ	1.9	7.8	17.9	33.4	50.3
Price realised	/GJ	$ -	$ 6.50	$ 7.00	$ 9.50	$ 9.60
Operating costs	/GJ	-$ 1.43	-$ 2.59	-$ 2.81	-$ 6.64	-$ 6.80
Net price	/GJ	-$ 1.43	$ 3.91	$ 4.19	$ 2.86	$ 2.80
Revenue	$m	0	51	126	317	483
Operating costs	$m	-3	-20	-50	-221	-342
EBITDAX	$m	-3	31	75	95	141
Capex	$m	-53	-68	-87	-133	-122
Tax	$m	0	0	0	0	0
FCF	$m	-56	-37	-11	-37	18
Discount Rate	%	9.6%				
NPV	$m	1,788	1,839	1,870	1,879	1,905
Risked	%	10%				
Risked NPV	$m	179	184	187	188	191

Source: MST Access.

Exhibit 37 – TBN: Reserves



Source: MST Access.

Exhibit 38 – TBN: CAPM estimates

CAPM	
Risk free rate	2.50%
Equity beta	1.5
Equity risk premium	4.72%
Cost of equity	9.6%
Debt	0%
Equity	100%
Interest rate	5.0%
Tax rate	30%
WACC	9.6%

Source: MST Access.

Assumptions in our DCF Valuation

- **Risk weighting:** TBN is subject to typical exploration asset risks given limited work has been done to date, more so on EP136 vs EP161. As such, we have risked EP136 at 10%, below EP161 at 15%.
- **Discount rate:** We have discounted our asset free cash flows at a 9.6% discount rate, to determine individual asset values.
- **Gas prices:** In line with MST, we have assumed domestic SE gas prices of $8/GJ FY22 through to $9.50/GJ in FY25, and LNG netback slight ahead of this. In light of the recent ACCC netback price series where the prices average A$11.20/GJ in 2022 (does not take into account transportation costs), there is upside risk to our assumptions. We assume initial gas from drilled wells in FY22 is not sold.
- **Well costs:** Based on experience of the US and Santos, considering technical learnings, fixed cost leverage and scale, we have assumed well cost improvements of 35% in FY22, scaling down to 8% in FY25 and rising by inflation from FY29+.
- **Wells drilled:** We assume the number of wells drilled at EP161 gets up to 4 p.a. by FY25, then 16 p.a. for full field development by FY30. At EP136, we assume 5 wells are drilled in both FY25 and FY26, ramping up to 30 wells p.a. for full field development by FY29.
- **Operating Costs:** We assume royalties of 10%, and cost inflation of 2% p.a.
- **Project life and depletion:** We have assumed both projects are net to TBN 3.1 TCF and are completely depleted. We estimate 5% pa field depletion with 27 years of production for EP161 and 13 years for EP136.
- **Costs:** We assume corporate overheads of $5m pa growing to $7m pa in FY26.
- **Site restoration:** We estimate site restoration of $15m net across both projects to be the book value for their remediation provisions.

Valuation Cross-Check: Sensitivity and Comparisons

Sensitivity analysis: key sensitivities are pricing and drilling delays

Exhibit 39 – Sensitivity analysis

Sensitivities	Valn Chg %	FCF positive	Funding shortfall ahead of FCF positive $m	Chg vs base $m
Base case		FY26	-156	
Price/Destination				
+10% change in our end market pricing	30.5%	FY24	-109	47
-10% change in our end market pricing	-31.6%	FY29	-275	-119
+10% change in transport costs	-11.6%	FY26	-177	-21
-10% change in transport costs	11.4%	FY26	-136	20
Sales from EP136 go to the LNG backfill, along with EP161	69.7%	FY26	-139	17
Well costs/drilling				
+1 percentage point change in well costs	-4.1%	FY26	-161	-5
-1 percentage point change in well costs	4.0%	FY26	-152	4
12mth delay in drilling at EP161	-7.3%	FY26	-150	6
12mth delay in drilling at EP136	-13.6%	FY27	-137	19

Source: MST Access.

Looking at the sensitivities above in Exhibit 39, a 12 month delay in drilling at EP136 will reduce our sum of the parts DCF valuation by 14% and delay TBN being FCF by another 12 months. The impact from a 12 month delay at EP161 is less impactful, seeing the valuation fall by 7% and FCF positive remaining at FY26.

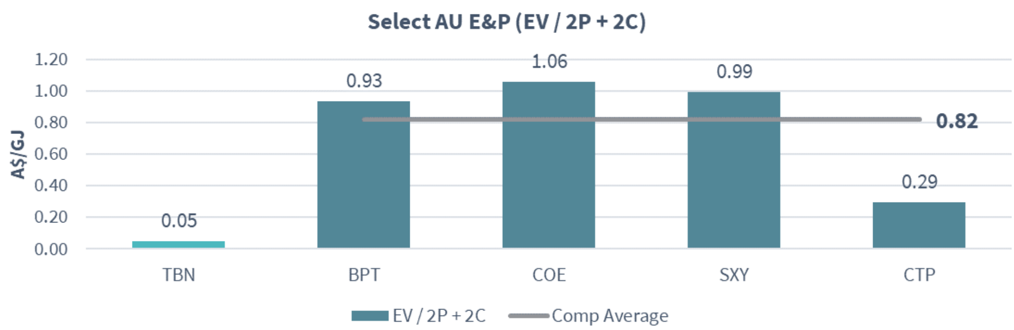
Looking at pricing: A 10% change in end market pricing will improve the valuation by 31% and could see TBN FCF positive 2 years earlier, by FY24, improving the funding shortfall to only $109m. If the destination for the gas at EP136 goes from the domestic SE market to LNG backfill, our valuation would nearly double as the earnings would benefit from lower transportation costs.

Peer comparison gives varying results: alternative EV suggests strong upside for TBN…

We have also taken an additional check on valuation through how the market values the reserves and resources of listed peers, using EV/2P+2C. This yields a much higher alternative enterprise valuation of ~$2.4bn for TBN (2,925 PJ assuming BP conversion x $0.82/GJ), likely as a result of more mature assets and as such, higher ascribed risk weightings by the market. The current share price implies $0.05/GJ for TBN.

Using our estimated unrisked EV of ~$3.2bn, the current share price implies that the market is only applying a risk weight to the assets of 8%.

Exhibit 40 – Comparable EV/resources



Source: MST Access. .

…while examining past transactions ends up with a much lower valuation

Looking at historical transactions, we examined Origin/Falcon's asset EP76 with contingent resource of 6.6 Tcf. It was a little trickier getting clarity on valuation in this way, given the embedded capex funding costs. However, this method ascribes a much lower valuation to TBN with EV of ~$170m (=$0.06/GJ). Again, this is a function of a much lower risk weighting ascribed to the assets, project infancy and possibly greater potential funding required.

Risks

We highlight the following risks to our investment view. Key risks centre on funding and unknown resource.

Management: A breakdown in the relationship with Jemena on the pipeline or JV partner Santos could delay the extraction of gas and thus revenue. Either party may fail to perform their contractual obligations. This could also lead to additional funding requirements. Management and the board may not manage the company or operational risks effectively which could lead to many negative impacts including the company becoming insolvent in the future.

Operational: Numerous operational risks include, but are not limited to, adverse weather conditions, environmental hazards, unforeseen increases in establishment costs, accidents, equipment failure, industrial disputes, technical issues, supply chain failure, labour issues and other unexpected events. They could result in damage to, or destruction of, production facilities, personal injury, environmental damage, increase operational costs and disrupt operations, possibly halting exploration.

Timing: Missing target timing on drilling, from a variety of reasons including equipment issues, presents a risk. This could see the company need to raise additional funding given delay in revenues.

Costs: Uncertainties and higher associated costs that could come from costs blow outs in exploration, drilling and extraction of the resource are risks. Future outbreaks of COVID could suspend the exploration program and would therefore likely negatively impact costs. The technical risk that comes with exploration drilling may see the quality of the resource lessened and increase the cost of extraction. The drilling could result in equipment failure, delaying timing and likely causing higher costs. Tighter labour markets could see an increase in project costs.

Funding: The company currently has no revenue. Additional funding may be required to support costs and the capex program. Lack of demand for assets or new equity may lead to weaker pricing and potentially an inability to raise additional funding for the company, which could lead to insolvency.

Resource: The resource quality and quantity are largely unknown given limited drilling to date. These results could come in below expectations and flow rates could decline faster than expected. There is no guarantee of success with exploration, nor that the gas will be commercially or economically viable.

Investment: Significant shareholding selling could put downward pressure on the share price.

Macroeconomic: A change in the supply and demand landscape for the domestic gas market and LNG gas market could reduce the price vs current estimates, which could see the resource become uneconomic. New or alternative options for supply could fulfill the demand requirements of gas buyers which could also leave the resource uneconomic.

Regulatory: There may be limited access to the licences relating to land access, landholders and Native Title holders, and/or permit tenures. Additional compensation could be required, or judicial decisions and legislation could halt the permits and the project. There may be additional regulatory requirements including, and not limited to, new requirements relating to climate change, environmental protection and energy policy. These outcomes may cause the project costs to increase, or the project to be stopped, and put a strain on funding.

Environmental: The gas activities could harm the environment due to an unexpected occurrence that could impact costs through rehabilitation and timing of the project. There is a risk of both community opposition and that environmental laws could change, again negatively impacting costs and timing with the additional risk of shutting down the project. There are transition (policy, legal, technology and market change) and physical (extreme weather events) risks associated with climate change that could cause delays in timing, higher costs and/or halting of the project.

The ESG Angle: Facilitating the Transition from Coal

Environmental: TBN Is Focused on Being Net-zero CO_2

TBN is committed to minimising the carbon emissions related to the development of the resource. The typical range of the percentage of contained CO_2 in reservoir gas (developed and undeveloped Australian natural gas deposits) is 1%–20%, according to the Carbon Storage Taskforce of the Federal Government. Tanumbirini-1 contained approximately 3% CO_2, at the very low end of the range, and has no major impurities such as sulphur or inerts. Additionally, the company intends to integrate renewable energy, carbon capture, utilisation, and storage (CCUS) and carbon offsets to come out at a net-zero CO_2 development.

Through new technologies, like the gas-powered drilling model using Aggreko engineered gas engines, together with the installation of a super capacitor, TBN hopes to gain some additional revenue. This will occur through flaring of gas from the testing wells, giving TBN the option to monetise to the NT local gas market (assuming infrastructure is already in place) whilst achieving a reduction in the cost of energy supply to drill rigs.

Social: Relationships with Traditional Land Owners

TBN maintains good relationships with the traditional land owners through Sacred Site clearance prior to any disturbance in preparation for drilling.

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