Maverick M1H well to be drilled, fractured and flow tested in 2H 2022

EP136 Pilot Development

TBN has stated the M1H well in EP136 is expected to be drilled in late August, with fracturing and flow testing to be completed by the end of CY 2022. Following the M1H flow test we expect a 2C contingent resource on EP136 to be booked (TBN targeting 300 billion cubic feet (Bcf) of 2C gas resource).

On the back of that booking we believe TBN will farm down 25 % of the license with a new partner funding additional wells in EP136 in CY 2023. TBN is targeting 1 trillion cubic feet (Tcf) of 2P reserves to be booked by the end of CY 2023.

On the basis that the well production data in CY 2022 and CY 2023 deliver commercial flow rates, we expect TBN will farm out an additional 25 % (on top of that mentioned above) of EP136 leading into the project sanctioning of a 100 million standard cubic feet per day (mmscfd) pilot development by the end of CY 2023.

TBN is aiming to get gas to market by the end of CY 2025 at which stage it is targeting a 2P reserve booking of 5 Tcf in EP136.

MST modelling of a 100 mmscfd pilot program

We have modelled a 20 year, 100 mmscfd, pilot program to see the valuation sensitivities to gas price received, production flows, operating costs, well capital expenditure and gas transportation to market costs. For a base case pilot program we have assumed a $10/gigajoule (GJ) sales gas price at Wallumbilla, initial well capital costs of $35 m/well declining over time to $20m per well, ~$1/GJ upstream operating costs, 5.0 mmscfd/1,000m lateral initial production flows and $4.30/GJ to transport gas to market.

On this basis the pilot program would earn an internal rate of return (IRR) of ~10 %. **We note if we lift the gas price received to $15/GJ, our base case ungeared IRR lifts from ~10 % to 45 %.**

If we then assume the same assumptions as our base pilot program for a larger development (TBN targeting 1,000 TJ per day production by CY 2030) **but assume gas transportation costs lower to $0.50/GJ in line with TBN's target through a new Jemena pipeline to Darwin, the IRR lifts to ~40 %.**

Funding available for the balance of CY 2022

We forecast net cash expenditure from the end of the first quarter to the end of CY 2022 will be ~$50 m comprising ~$45 m on M1H, ~$3.5 m on seismic and ~$7.5m for corporate costs offset by $7.5m to be received from the Beetaloo Cooperative Drilling Program to partly fund the M1H well. Cash at 31 March was $55m.

Valuation

We have a spot valuation of $0.58 per share for TBN (see inside report for methodology).

The primary risk to the valuation and stock price in the near term is the success of achieving commercial flow rates at the M1H well.

Tamboran Resources (TBN) is a gas exploration company that aims to prove up new 2P reserves and develop gas production out of the Beetaloo Basin in the Northern Territory in order to supply the Australian domestic market and Asian LNG market.
http://www.tamboran.com/

Stock	TBN.ASX
Price	A$0.21
Market cap	A$157 m
Cash position	A$55 m (March 2022)
Valuation (per share)	A$0.58 (Unchanged)

News Flow and Catalysts	
2H 2022	Additional flow testing results from EP161 Tanumbirini T2H and T3H
2H 2022	EP136 Maverick M1H well to be drilled, fracked and flow tested
2H 2022	Targeting an initial booking of 2C contingent resource on EP136

TBN Share Price (A$)

Source: FactSet

David Fraser
david.fraser@mstaccess.com.au

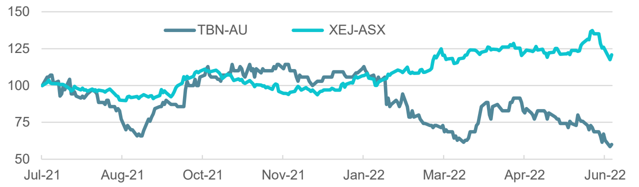
Financial data

Tamboran Resources — TBN-AU

Year end 30 June

MARKET DATA			
Price	**$**		**0.21**
52 week high / low	A$	0.40	0.21
Valuation	**A$**		**0.58**
Market capitalisation	A$m		156.9
Shares on issue (basic)	**m**		**747.4**
Options	m		43.2
Shares on issue (diluted)	**m**		**790.6**

12 month relative performance versus S&P/ASX 200 Energy Index



INVESTMENT FUNDAMENTALS		FY20A	FY21A	FY22E	FY23E
EPS reported	¢	(15.5)	(19.2)	(1.7)	(1.4)
EPS underlying	**¢**	**(15.5)**	**(19.2)**	**(1.7)**	**(1.4)**
P/E reported	**x**	**(2.3)**	**(1.8)**	**(12.3)**	**(14.6)**
P/E underlying	**x**	**(2.3)**	**(1.8)**	**(12.3)**	**(14.6)**
Dividend	**¢**	**0.0**	**0.0**	**0.0**	**0.0**
Payout ratio	%	0.0%	0.0%	0.0%	0.0%
Yield (Y/E/ spot)	**%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Net Tangible Assets	$m	(39.6)	104.4	123.4	125.2
Net Tangible Assets per share	¢	(42.2)	16.0	16.5	15.2
Free cash flow	$m	(20.9)	(21.8)	(49.6)	(51.7)
Free cash flow yield	%	(63.8)	(50.3)	(33.4)	(31.2)
Price to Free cash flow	x	(1.6)	(2.0)	(3.0)	(3.2)
Year end shares	**m**	**94**	**653**	**747**	**822**
Average shares on issue	m	94	124	708	791
Year end / Spot share price	$	0.35	0.35	0.21	0.21
Market cap (Y/E / Spot)	$m	33	229	157	173
Net debt /(cash)	**$m**	**(6)**	**(63)**	**(45)**	**(6)**
Enterprise value	**$m**	**27**	**165**	**112**	**166**
EV/EBITDAX	**x**	**n/m**	**n/m**	**n/m**	**n/m**
Gearing (net debt / EBITDAX)	**x**	**n/m**	**n/m**	**n/m**	**n/m**

RESERVES & RESOURCES

	2U Prospective			2C Contingent	
Net Bcf to TBN	**EP161**	**EP136**	**Total**	**EP161**	**EP136**
TBN share	*25%*	*100%*		*25%*	*100%*
Velkerri C	3,492	6,050	9,542	25	-
Velkerri B	6,526	9,698	16,224	128	-
Velkerri A	2,078	3,037	5,115	-	-
Lower Kyalla	217	232	449	-	-
Total (Bcf)	**12,312**	**19,017**	**31,329**	**153**	**-**
Low estimate (1U)	7,100	11,200	18,300		
High estimate (3U)	24,800	37,800	62,600		

Unrisked 1C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C		16	
Velkerri B		32	
Velkerri A		-	
Total (Bcf)	**11**	**48**	**336%**

Unrisked 2C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C	11	25	127%
Velkerri B	18	128	611%
Velkerri A			
Total (Bcf)	**29**	**153**	**428%**

Unrisked 3C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C		34	
Velkerri B		328	
Velkerri A		-	
Total (Bcf)		**362**	

PROFIT AND LOSS		FY20A	FY21A	FY22E	FY23E
Sales	**$m**	**0.0**	**0.0**	**0.0**	**0.0**
Other income	$m	0.0	2.5	0.0	0.0
Operating costs	$m	(12.4)	(18.1)	(12.1)	(11.3)
EBITDAX	**$m**	**(12.4)**	**(15.6)**	**(12.1)**	**(11.3)**
Exploration & evaluation expensed	$m	0.0	0.0	0.0	0.0
EBITDA	$m	**(12.4)**	**(15.6)**	**(12.1)**	**(11.3)**
Depreciation & Amortisation	$m	(0.1)	(0.4)	(0.1)	(0.1)
EBIT	**$m**	**(12.5)**	**(16.0)**	**(12.2)**	**(11.4)**
Net interest	$m	(2.0)	(7.8)	0.1	0.1
Pretax Profit	$m	**(14.5)**	**(23.8)**	**(12.1)**	**(11.3)**
Tax expense	$m	0.0	0.0	0.0	0.0
NPAT	**$m**	**(14.5)**	**(23.8)**	**(12.1)**	**(11.3)**

BALANCE SHEET		FY20A	FY21A	FY22E	FY23E
Cash	$m	5.6	63.1	44.6	6.4
Receivables	$m	0.5	0.4	0.4	0.4
Other	$m	0.0	0.0	0.0	0.0
Current assets	$m	**6.1**	**63.6**	**45.1**	**6.8**
Exploration & Evaluation	$m	15.7	46.6	84.7	125.2
Oil and Gas assets	$m	0.7	0.7	0.6	0.5
Right of use assets	$m	2.6	1.4	1.0	0.7
Other	$m	0.0	0.3	0.3	0.3
Non current assets	$m	**19.0**	**49.0**	**86.6**	**126.7**
Total Assets	**$m**	**25.1**	**112.6**	**131.7**	**133.5**
Accounts Payable	$m	3.8	5.7	6.0	6.3
Borrowings	$m	0.0	0.0	0.0	0.0
Other	$m	0.8	1.3	1.3	1.3
Current liabilities	$m	**4.5**	**7.0**	**7.3**	**7.6**
Borrowings	$m	0.0	0.0	0.0	0.0
Provisions	$m	2.3	1.1	0.8	0.6
Other	$m	**57.9**	**0.1**	**0.1**	**0.1**
Non current liabilities	$m	**60.1**	**1.2**	**1.0**	**0.8**
Total Liabilities	**$m**	**64.7**	**8.2**	**8.2**	**8.4**
Equity	$m	20.5	183.9	218.8	233.8
Retained earnings	$m	(64.3)	(88.1)	(100.2)	(111.6)
Reserves / Other	$m	4.2	8.6	4.9	2.9
Total equity	**$m**	**(39.6)**	**104.4**	**123.4**	**125.2**

CASH FLOW		FY20A	FY21A	FY22E	FY23E
EBITDAX	$m	**(12.4)**	**(15.6)**	**(12.1)**	**(11.3)**
Employment shares / Other non cash	$m	0.3	4.6	0.0	0.0
Working Capital / Other	$m	3.1	2.5	0.0	0.0
Net interest	$m	0.1	(0.1)	0.1	0.1
Tax paid	$m	0.0	0.0	0.0	0.0
Operating cash flow	**$m**	**(8.9)**	**(8.6)**	**(10.5)**	**(11.2)**
Exploration & development	$m	(12.0)	(13.2)	(38.1)	(48.0)
Beetaloo grants	$m	0.0	0.0	0.0	7.5
Other	$m	0.0	0.0	(1.0)	0.0
Investing cash flow	**$m**	**(12.0)**	**(13.2)**	**(39.1)**	**(40.5)**
Change in Equity	$m	0.1	83.0	35.0	15.0
Increase / (Decrease) in borrowings	$m	0.0	0.0	0.0	0.0
Dividend	$m	0.0	0.0	0.0	0.0
Transaction costs / Other	$m	(0.1)	(3.7)	(3.8)	(1.5)
Financing cash flow	**$m**	**(0.0)**	**79.3**	**31.2**	**13.5**
FX	$m	0.0	0.0	0.0	0.0
Change in Cash	$m	(20.9)	57.5	(18.5)	(38.3)
Cash year end	**$m**	**5.6**	**63.1**	**44.6**	**6.4**

Source: MST Access, Company data

Tamboran Resources Investment Thesis

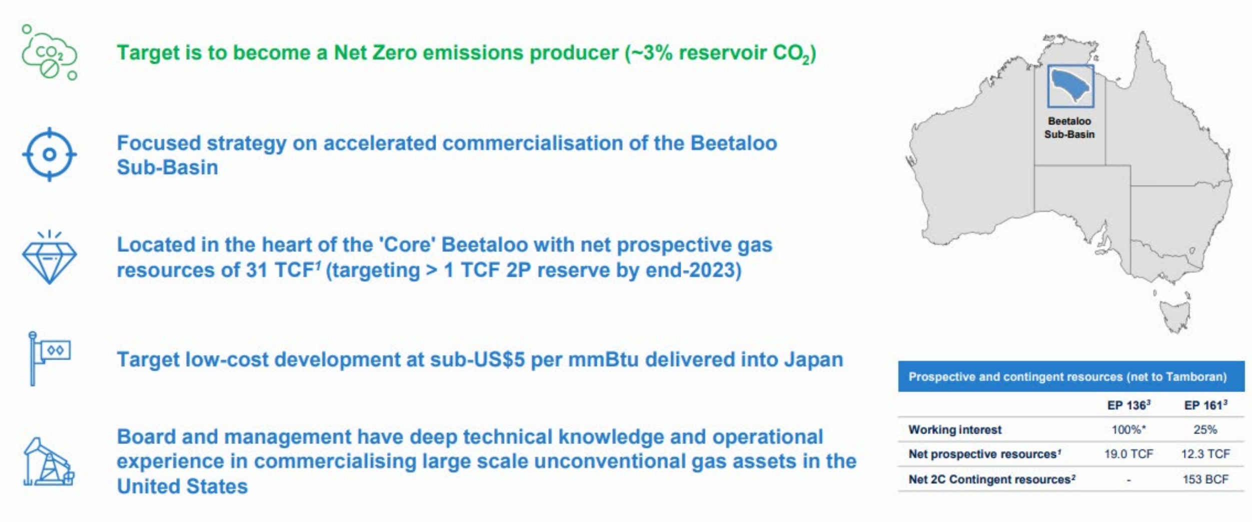
TBN has a stated prospective 2U resource (net to TBN) of 31.3 Tcf, made up of 12.3 Tcf at EP161 (25% interest) and 19.0 Tcf at EP136 (100% interest).

TBN is looking to target the undersupplied Australian LNG markets and domestic gas markets.

We forecast that TBN has cash available (net cash at 31 March of $55m) to fully fund and flow test the Maverick M1H well, forecast to be spud in 2H CY 2022.

Valuation: We have a spot valuation of $0.58 per share for TBN (see Pg 9 for methodology).

Figure 1 – TBN at a glance



Source: Company

Target timeline to first gas

Figure 2 – Targeting first gas in CY 2025/CY2026

	2021	2022	2023	2024	2025/2026
Upstream	Drilled and tested Tanumbirini 2H & 3H in EP 161	Drilling M1H well in EP 136	Drill M2H and 3H in EP 136 Drill Jibera South 1H in EP 161	Commence development activities for ~100 mmscfd Maverick Pilot Development	Targeting first gas from Maverick Pilot Development
Reserves / Resources	EP 161: 153 BCF 2C gas resources	Targeting ~300 BCF 2C gas resources	Targeting >1 TCF 2P gas reserves		Targeting >5 TCF 2P gas reserves
Midstream		Undertake FEED studies for midstream infrastructure solution	Midstream Final Investment Decision with Jemena JV		Targeting first gas from Maverick Pilot Development
Technology		Secure modern US drilling technology for 2023 EP 136 drilling			
Offtake		Signed non-binding MOU with large Asian gas buyer	Initiate East Coast gas offtake discussion for 1 TCF over 20-years	Finalise Gas Sales Agreement	Target first gas sales to investment grade customer(s)
Funding	**Fully Funded upstream and midstream activity** IPO (July 2021), Sheffield raise (November 2021), Beetaloo Cooperative Development Program (BCDP) grant ($7.5 million)		Opportunities include farm-down, equity, pre-sale of gas	Opportunities include farm-down, US IPO, pre-sale of gas	

Source: Company

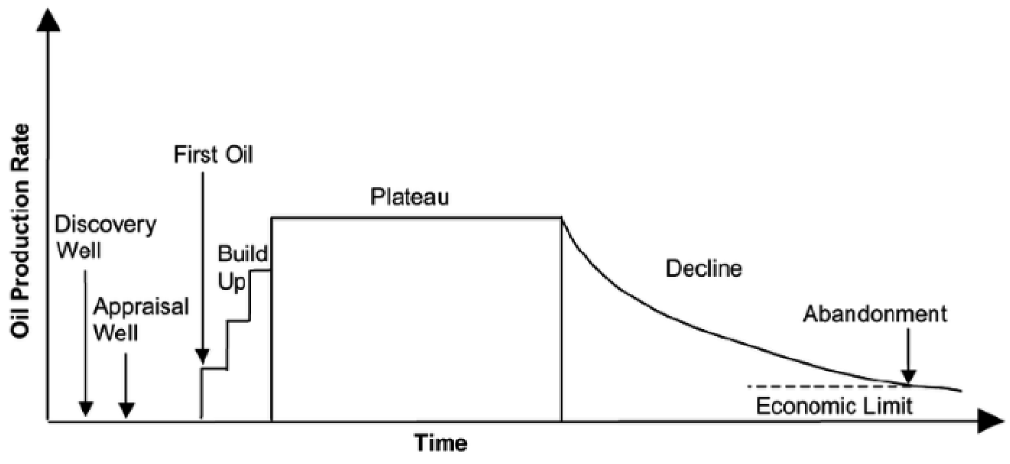
Just a reminder - Shale gas production is different

As a reminder and noting every fossil fuel producing field is different, we have tabled below examples of generalised production profiles for conventional oil and gas fields, coal bed methane fields and TBN's proposed shale gas fields.

Conventional oil and gas production profile

A typical oil field will ramp up production as wells are brought online and then production typically plateaus for a period while reservoir pressure is maintained (often water driven) before starting to decline over time as reservoir pressure drops and water cut increases etc.

Figure 3 – Conventional oil and gas production profile

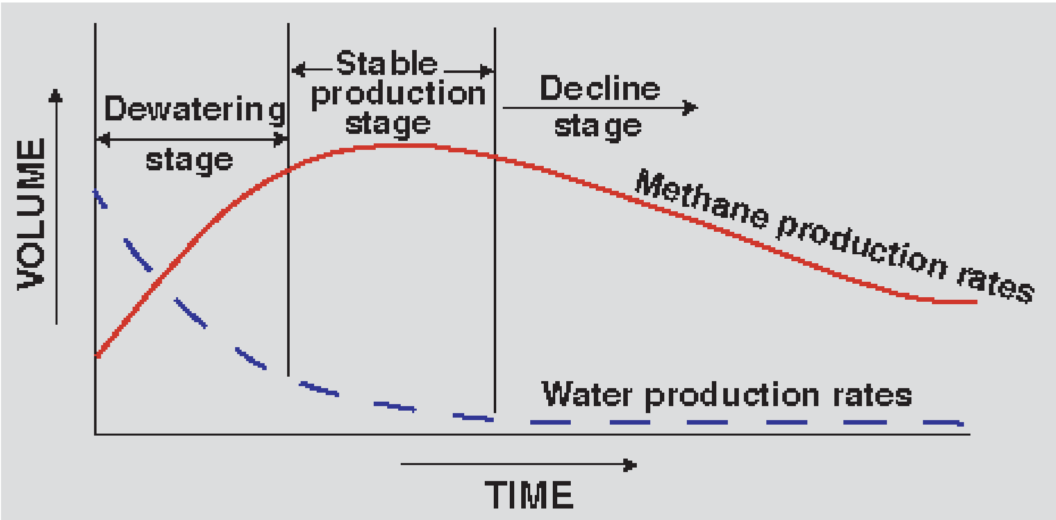


Source: Feygin and Ryzhik (2001) and Robelius (2007)

Unconventional coalbed methane production profile

Coalbed methane wells have different production profiles than conventional oil and gas wells and unconventional shale gas wells. Before gas can be produced, the water in the coal seam has to be pumped out lowering the hydrostatic pressure. This allows the gas adsorbed in the coal to desorb and any free gas trapped in cleats to flow to the surface. Because of the time taken to dewater, the ramp up in gas flow can be up to a year after well completion.

Figure 4 – Unconventional coal seam gas production profile



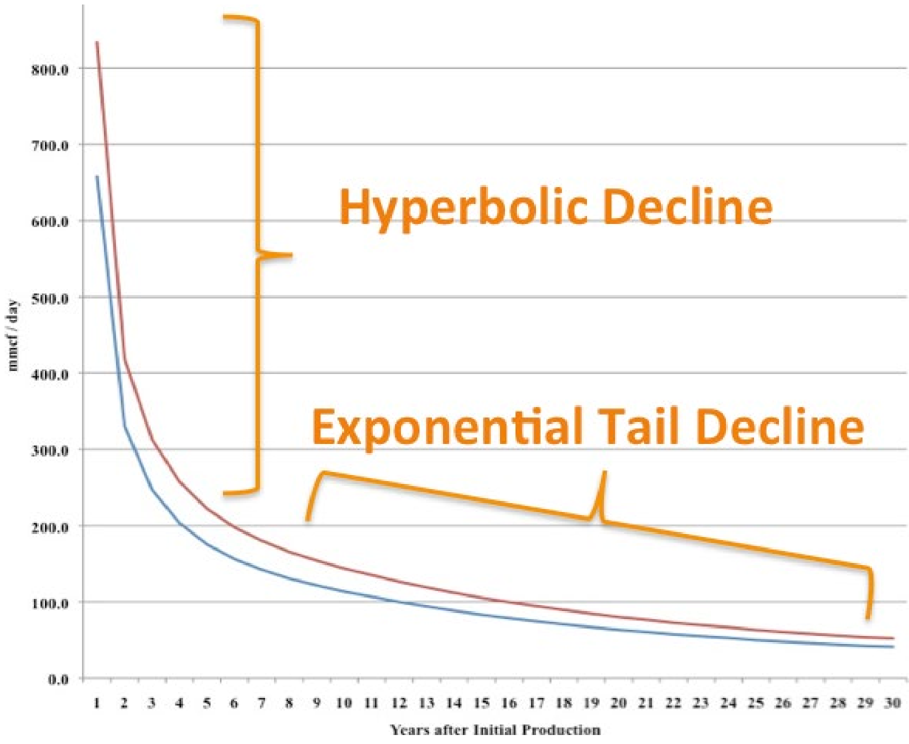
Source: Kuuskraa and Brandenberg (1989)

Unconventional shale gas production profile

The production profile of a typical shale well entails a rather sharp initial decline in production followed by a much slower rate of decline.

It has been established that the initial production decline in a shale well can be best demonstrated by hyperbolic decline modelling and then decline rates follow an exponential decline path. The decline rate at which it switches from hyperbolic to exponential is known as the “minimum decline rate” or “terminal decline rate”. This minimum decline rate is chosen based on wells producing from the same or similar reservoirs that have already experienced the change from hyperbolic to exponential decline.

Figure 5 – Prospective and Contingent Resources



Source: Penn State Department of Energy and Mineral Engineering

EP136 Pilot program

Production and well forecasts

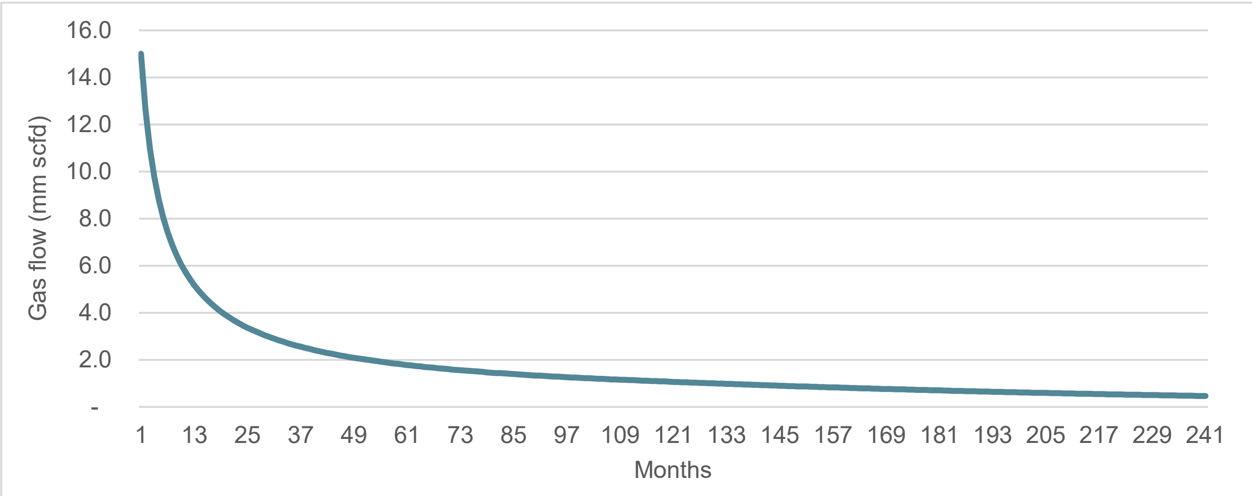
We have modelled a potential production profile so as to forecast a model for the proposed pilot program for EP136 to determine the project cash flows and capital requirements using typical production factors seen in the Marcellus and other shale gas production basins.

Key factors used are:

- Initial flow rates of 15 mmscfd based on 5.0 mmscfd per 1,000 m laterals with 3,000 m laterals to be drilled.
- Initial decline rates of 90 %.
- Minimum decline rate of 8 %.
- Hyperbolic coefficient (b factor) of 1.3.

As can be see below well production is forecast to by ~2/3rds over the first 12 months and drops from 15 mmscfd to ~2.0 mmscfd over the first five years. (Model available on request).

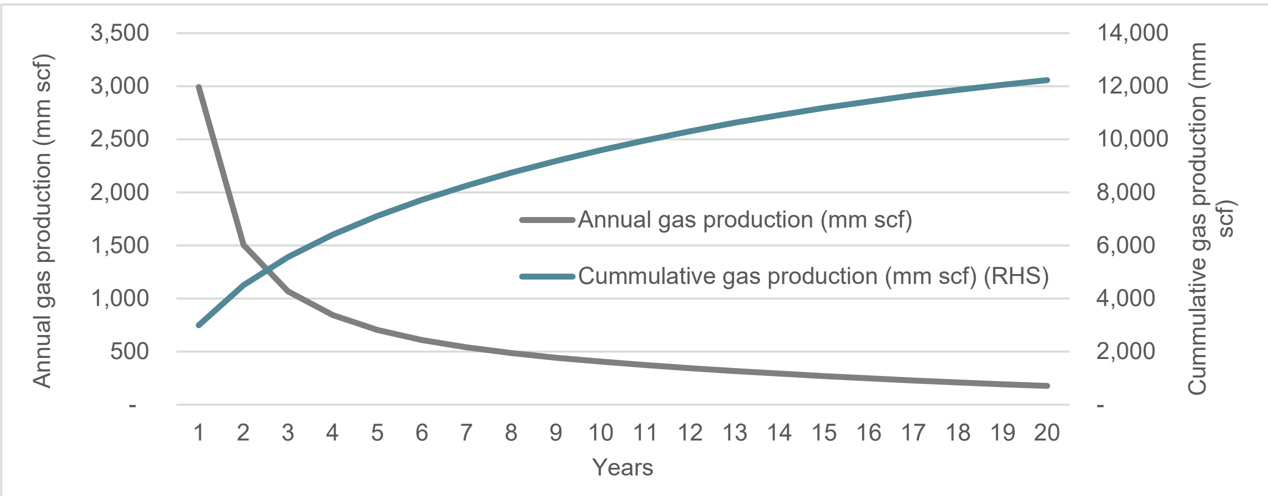
Figure 6 – Forecast well production profile



Source: Company, MST

Total gas production, or estimated ultimate recovery (EUR), over 20 years is estimated at ~12 Bcf (our model duration) with ~14 Bcf produced over a 40-year time frame.

Figure 7 – Forecast well annual production profile



Source: Company, MST

As a result of our calculated well performance, **we forecast that ~13 wells will be required in the first year of the development (assuming ~ 2 wells every 2 months) followed by 7 wells in Year 2,** followed by 6 in Year 3, then 4 wells per annum for a few years and then ~ 3 wells per annum on an ongoing basis. This would allow TBN to produce ~110 mmscfd of well head gas which would result in ~100 mmscfd of sales gas to be sent to market. Clearly as the production decline flattens and the number of wells lifts, the number of new wells per annum required falls.

Figure 8 – First ten-year forecast production profile and well capex required

Year	1	2	3	4	5	6	7	8	9	10
Gas produced (Bcf)	25.5	40.0	42.4	40.9	39.7	40.0	40.6	40.0	40.0	40.4
Implied gas produced (mm scfd)	70	110	116	112	109	110	111	110	110	111
Gas produced (PJ)	26.9	42.2	44.8	43.2	41.9	42.2	42.8	42.2	42.3	42.6
Percentage CO_2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
CO_2 (Bcf)	0.8	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
CO2 (t)	41,836	65,613	69,568	67,084	65,095	65,609	66,552	65,642	65,662	66,235
Other gas shrinkage to net gas sold	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Other gas shrinkage to net gas sold	1.3	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sales gas sold (Bcf)	23.5	36.8	39.0	37.6	36.5	36.8	37.3	36.8	36.8	37.2
Implied sales gas (mm scfd)	**64**	**101**	**107**	**103**	**100**	**101**	**102**	**101**	**101**	**102**
Sales gas sold (PJ)	24.8	38.8	41.2	39.7	38.5	38.8	39.4	38.9	38.9	39.2
Well capex (A$m)										
Number wells drilled	13	7	6	4	4	4	4	3	3	3
Cummulative wells drilled	13	20	26	30	34	38	41	45	48	51
Average well cost	34	31	29	26	24	21	20	21	21	22
Well capex (A$m)	**425**	**225**	**173**	**102**	**93**	**83**	**75**	**68**	**70**	**72**

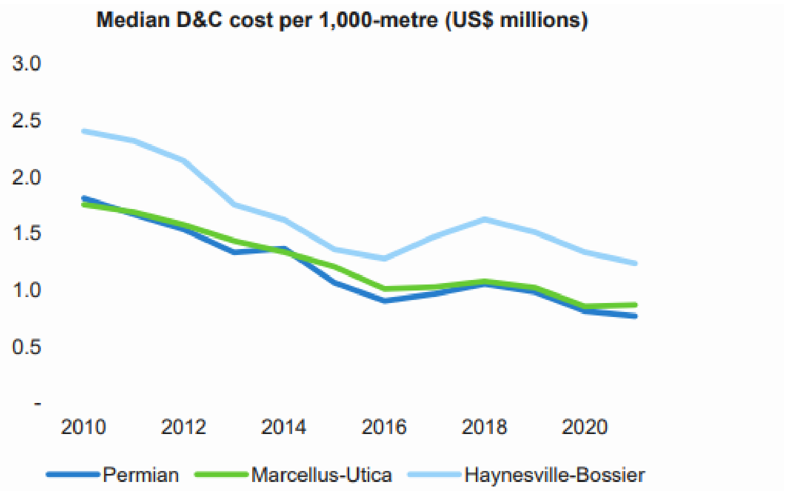
Source: MST

On this basis, in the first three years of the pilot program, ~26 wells will need to be drilled which will clearly require a meaningful level of new capital. By this stage however, TBN will have booked a 2P reserve from which it will be able to secure reserve backed lending (RBL) to fund the project. Additionally, it may choose to farm out an additional stake to lower its holding and to reduce TBN's equity requirements.

We have assumed TBN become more efficient with its well drilling and average well costs fall from A$34m to $20m per well over the first six years as per the management teams experience in the United States shale basins.

We also note, if initial gas flows are higher than 5.0 mmscfd, the number of wells required to meet a 100 mmscfd pilot program would be lower; e.g. **If initial flows are 7.5 mmscfd the number of wells to be drilled in the first three years would drop from ~26 wells to ~17 wells, a capex saving of $286m**.

Figure 9 – Cost reduction in capex (drilling, completion and facilities equipment) have fallen 50% since 2010



Source: Company, Rystad Energy

Forecast financials

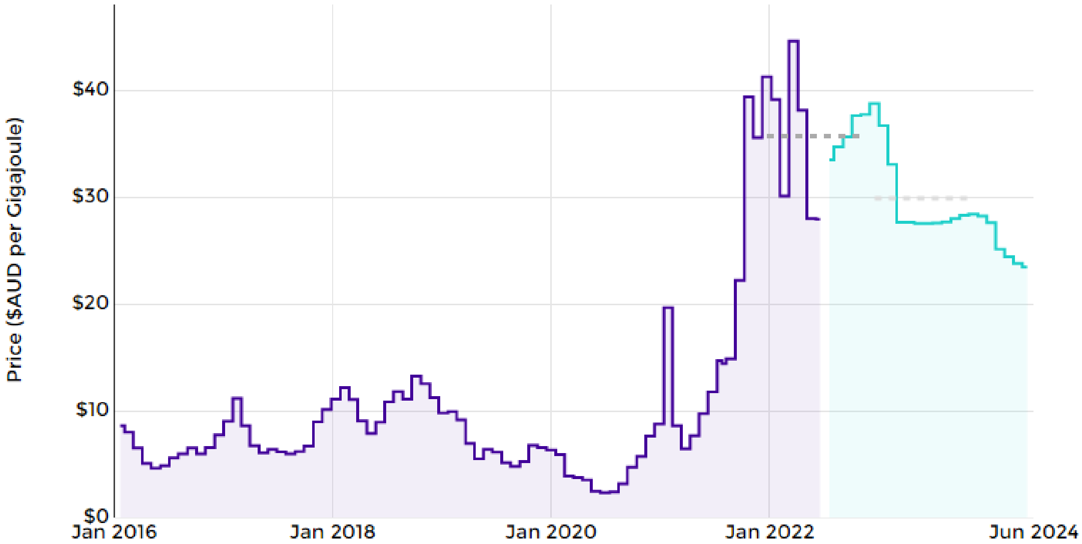
With a production profile and a forecast capex program we have generated the forecast cash flows for the program. See Appendix 5 for the TBN key target assumptions for the pilot program and transport costs to market.

MST key assumptions are:

- Starting sales gas price of A$10/GJ.

We do not believe this is unduly optimistic given where current liquified natural gas (LNG) netback prices are currently pricing (16 June 2022) as estimated by the Australian Competition & Consumer Commission (ACCC)) and potentially could be conservative. NB: CY 2023 forward pricing averaging $30/GJ.

Figure 10 – Historical and forward LNG netback price at Wallumbilla (A$/GJ) – CY 2023 average $30/GJ



Source: ACCC, 16 June 2022.

- 20-year project life.
- Gas price and cost inflation of 2.5% per annum.
- Fixed operating costs of $15 m per annum inflating at 2.5%.
- Variable operating costs of $0.50/GJ produced inflating at 2.5%.
- Private royalties of 3% of sales. We assume the current 10% third party overriding royalty interests (ORRI) will be reduced to 3% at a cost of US$17m (See Prospectus Pg 55 for detail) prior to the pilot program commencement.
- State royalties at 10% of gross value.
- We assume produced gas contains 3% of carbon dioxide and an additional 5% of gas shrinkage occurs through plant use flaring etc. Carbon tax of $30/tonne CO2 produced.
- Transport costs for pilot program of ~$4.30/GJ comprising $1.59/GJ for the Northern Gas Pipeline (NGP), $1.15/GJ for the Carpentaria Gas Pipeline (CGP) and $1.54/GJ for the South-West Queensland Pipeline (SWQP). We assume additional compression will be required to get gas to Wallumbilla for the SWQP, otherwise the tariff is $1.32/GJ]. See Appendix 4.
- We assume the cost of constructing a 100 mmscfd pipeline from the production areas to the NGP is funded by Jemena and is incorporated in our forecast operating costs. NB: TBN alternatively could pipe across to the Amadeus Gas Pipeline through an expanded MacArthur River Pipeline (See Appendix 4), so capex would be lower but for the life of the pilot program haulage tariffs would be slightly higher.
- Amortisation of well capital expenditure in line with gas production.

We table below our forecast base case pilot program forecasts assuming a $4.30 transportation haulage tariff.

Figure 11 – Forecast cash flows for Pilot program (10 years of a 20-year pilot program)

Year	1	2	3	4	5	6	7	8	9	10
Gas produced (Bcf)	25.5	40.0	42.4	40.9	39.7	40.0	40.6	40.0	40.0	40.4
Implied gas produced (mm scfd)	70	110	116	112	109	110	111	110	110	111
Gas produced (PJ)	26.9	42.2	44.8	43.2	41.9	42.2	42.8	42.2	42.3	42.6
Percentage CO_2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
CO_2 (Bcf)	0.8	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
CO2 (t)	41,836	65,613	69,568	67,084	65,095	65,609	66,552	65,642	65,662	66,235
Other gas shrinkage to net gas sold	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Other gas shrinkage to net gas sold	1.3	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sales gas sold (Bcf)	23.5	36.8	39.0	37.6	36.5	36.8	37.3	36.8	36.8	37.2
Implied sales gas (mm scfd)	**64**	**101**	**107**	**103**	**100**	**101**	**102**	**101**	**101**	**102**
Sales gas sold (PJ)	24.8	38.8	41.2	39.7	38.5	38.8	39.4	38.9	38.9	39.2
Inflation	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Gas price (A$/GJ)	10.00	10.25	10.51	10.77	11.04	11.31	11.60	11.89	12.18	12.49
Sales revenue	**248**	**398**	**433**	**428**	**425**	**439**	**457**	**462**	**474**	**490**
Private Royalties	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Private Royalties	(7)	(12)	(13)	(13)	(13)	(13)	(14)	(14)	(14)	(15)
Net Sales	**240**	**386**	**420**	**415**	**413**	**426**	**443**	**448**	**459**	**475**
Fixed operating costs	(15)	(15)	(16)	(16)	(17)	(17)	(17)	(18)	(18)	(19)
Variable operating costs ($/GJ)	0.50	0.51	0.53	0.54	0.55	0.57	0.58	0.59	0.61	0.62
Variable operating costs	(13)	(22)	(24)	(23)	(23)	(24)	(25)	(25)	(26)	(27)
Operating costs	(28)	(37)	(39)	(39)	(40)	(41)	(42)	(43)	(44)	(45)
Gross operating cash flow	**212**	**349**	**380**	**375**	**373**	**385**	**401**	**405**	**415**	**430**
State royalties	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
State royalties	(21)	(35)	(38)	(38)	(37)	(39)	(40)	(41)	(42)	(43)
Carbon tax ($/ t CO_2)	30	31	32	32	33	34	35	36	37	37
Carbon tax	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Darwin (New Jemena pipeline) ($/GJ)	0.50 - 1.00									
Wallumbilla (New Jemena pipeline) ($/GJ)	2.00									
East coast via existing infrastructure ($/GJ)	4.30									
Transport cost (A$/GJ)	4.30	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37
Transport costs	(106)	(171)	(186)	(184)	(183)	(189)	(196)	(199)	(204)	(211)
Tax	0	(10)	(14)	(17)	(18)	(21)	(24)	(25)	(26)	(28)
Operational cash flow	**83**	**131**	**140**	**135**	**132**	**135**	**139**	**139**	**141**	**146**
Well capex (A$m)	**425**	**225**	**173**	**102**	**93**	**83**	**75**	**68**	**70**	**72**
Free cash flow	**(342)**	**(94)**	**(33)**	**32**	**40**	**52**	**64**	**70**	**71**	**74**
20 year ungeared IRR	**9.4%**									

Source: Company, MST

Based on our assumptions the pilot program will earn an internal rate of return (IRR) of ~10 %. We note if we lift the forecast gas price received to $15/GJ, our base case ungeared IRR lifts from ~10 % to 45 %.

If we then assume the same assumptions as our base pilot program for a larger development (TBN targeting 1,000 TJ per day production by CY2030) but assume **gas transportation costs lower to $0.50/GJ to $1.00/GJ through a new Jemena pipeline to Darwin, the IRR lifts to ~35% to 40 %.**

If we assume gas prices of $15/GJ and a $1.00/GJ transportation price to Darwin, the IRR lifts to ~90%.

Valuation demonstrates material share price upside potential

We derive a spot valuation for TBN of $0.58 per share.

We have assumed, TBN and its partners have converted 7.5% of the gross prospective resource (5.1 Tcf) in EP161 and EP136 to 2P reserve and 2C resource by the end of CY 2025. NB: TBN are targeting 5 Tcf of 2P reserves by CY 2025.

We assume TBN farms out 25% of EP136 in late early CY2023 to fund further exploration and development wells in EP136 with a further farm down to 50% heading into project sanctioning in late CY 2024/early CY2025.

Thus, TBN's net share of the reserve and resource bookings in FY25 is ~1.0 TJ at EP161 and ~0.75 Tcf at EP136.

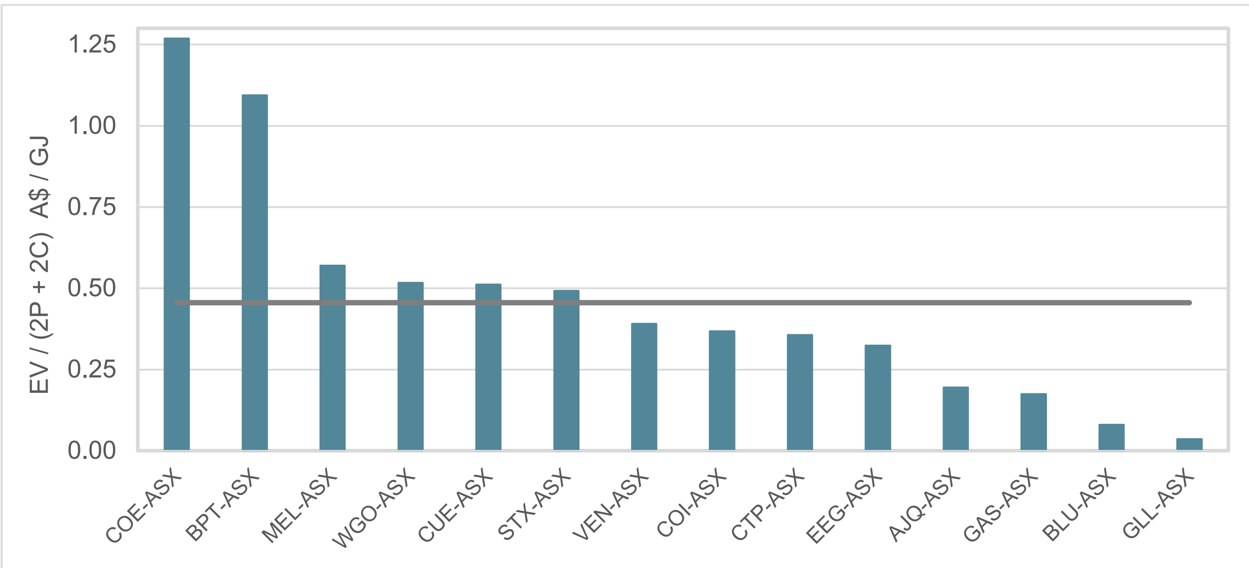
Figure 12 – FY25 Valuation based on average EV/(2P + 2C) multiples ($/GJ))

Gross Prospective 2U	EP161	EP136	Total
Tcf	49.2	19.0	68.3
Assumed conversion to 2C & 2P	7.5%	7.5%	7.5%
2P Reserve & 2C Resource	EP161	EP136	Total
Tcf	3.7	1.4	5.1
TJ	3.9	1.5	5.4
Other holders in License	75%	50%	
TBN's share	**25%**	**50%**	
TBN share (TJ)	**0.97**	**0.75**	**1.73**
EV/ (2P+2C) (A$/GJ)	*0.50*	*0.50*	*0.50*
Value ($m)	487	376	863
Shares on issue end CY 2025 (m)	908	908	908
End CY 2025 value per share	$0.54	$0.41	**$0.95**
Discounted back at			*15.0%*
Spot valuation per share			**$0.58**

Source: MST Access.

We then value TBN's net 1.7 TJ at $0.50/ GJ, in line with the average A$/GJ of 2P reserve plus 2C resource for similar listed Australian exploration and production companies (Figure 13).

Figure 13 – Peer comparisons on a 2P+2C basis (A$/GJ) – Average ~$0.50/GJ



Source: MST Access. FactSet (Prices at 17 June 2022), Company data

We then divide by the forecast diluted shares on issue at the end of FY25 (assumes all options and performance shares issue and two capital raises in FY23 and FY24 totalling $30m occur) to get a FY 25 valuation which we discount back to today at a cost of equity of 15% to get $0.58 per share.

We highlight that on this basis, if TBN traded at $1/GJ at the end of CY 2025, the implied valuation for TBN today would be $1.16.

Risks

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, securing routes to markets, 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, and macroeconomic risk.

Appendix 1 - Resources and Reserves

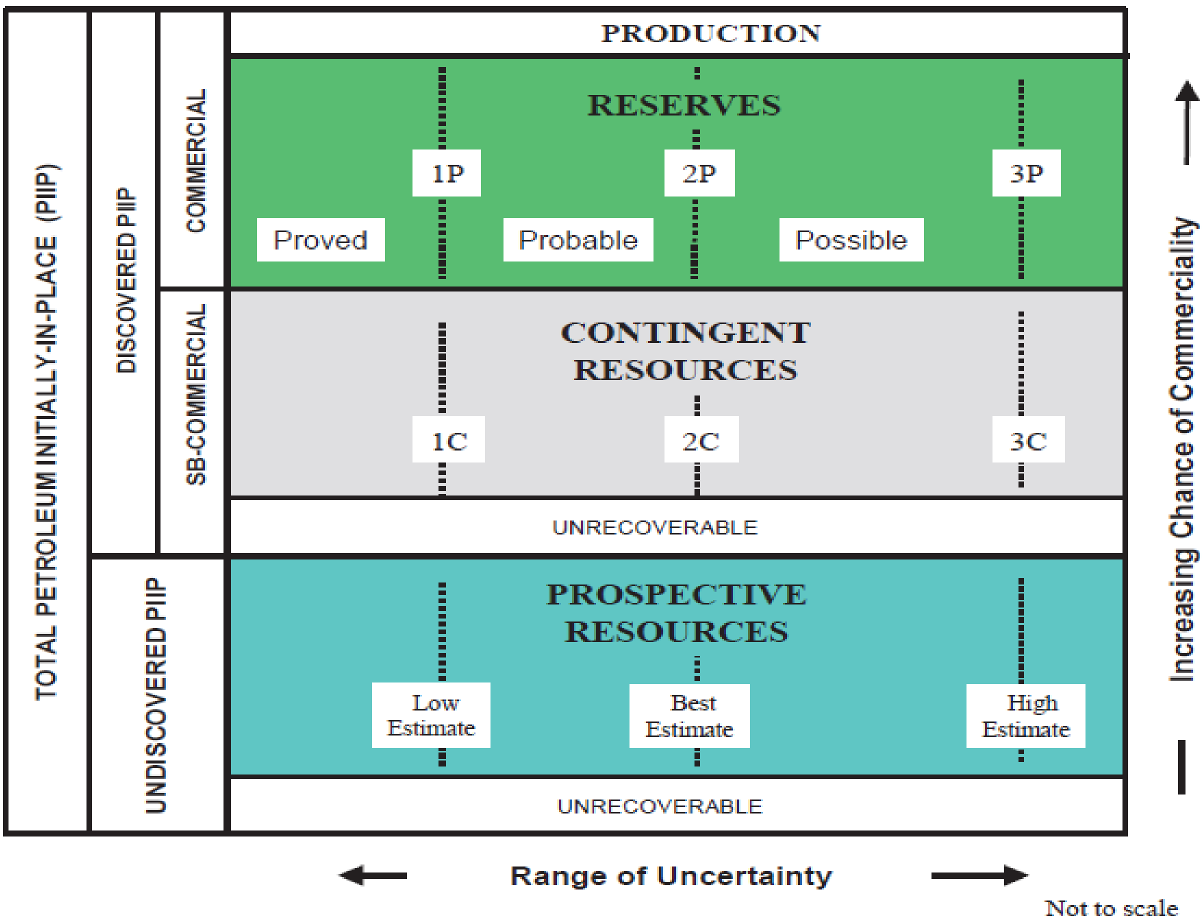
We note below the three categories into which estimated quantities of potentially recoverable petroleum can be placed: Prospective Resources, Contingent Resources and Reserves. Within each category, three estimates are designated to describe the range, with greater certainty at the low end and less certainty at the high end.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but where the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. The categories within Reserves, in order of decreasing certainty, are Proved, Probable and Possible.

Figure 14 – Resources and Reserves



Source: PRMS Resources Classification.

Figure 15 – Tamboran Resources and Reserves

Gross Bcf	Prospective 2U EP161	Prospective 2U EP136	Total Prospective 2U	Contingent 2C Resource EP161	Contingent 2C Resource EP136
Velkerri C	13,969	6,050	20,019	100	-
Velkerri B	26,102	9,698	35,800	512	-
Velkerri A	8,310	3,037	11,347	-	-
Lower Kyalla	867	232	1,099	-	-
Total (Bcf)	**49,248**	**19,017**	**68,265**	**612**	**-**
Low estimate	28,400	11,200	39,600		
High estimate	99,200	37,800	137,000		

Net Bcf to TBN	Prospective 2U EP161	Prospective 2U EP136	Total Prospective 2U	Contingent 2C Resource EP161	Contingent 2C Resource EP136
TBN share	***25%***	***100%***		***25%***	***100%***
Velkerri C	3,492	6,050	9,542	25	-
Velkerri B	6,526	9,698	16,224	128	-
Velkerri A	2,078	3,037	5,115	-	-
Lower Kyalla	217	232	449	-	-
Total (Bcf)	**12,312**	**19,017**	**31,329**	**153**	**-**
Low estimate	7,100	11,200	18,300		
High estimate	24,800	37,800	62,600		

Unrisked 1C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C		16	
Velkerri B		32	
Velkerri A			
Total (Bcf)	**11**	**48**	**336%**

Unrisked 2C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C	11	25	127%
Velkerri B	18	128	611%
Velkerri A			
Total (Bcf)	**29**	**153**	**428%**

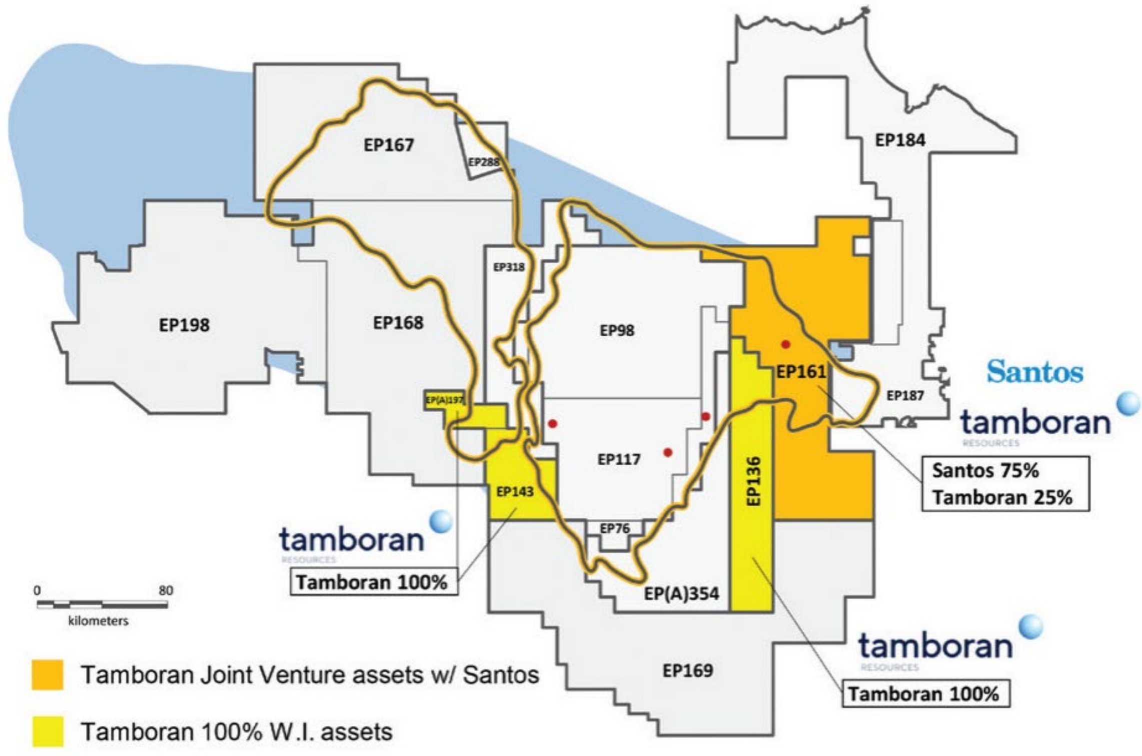
Unrisked 3C contingent resources

EP161 (25%)	At IPO	Updated	Lift
Velkerri C		34	
Velkerri B		328	
Velkerri A			
Total (Bcf)		**362**	

Source: Company.

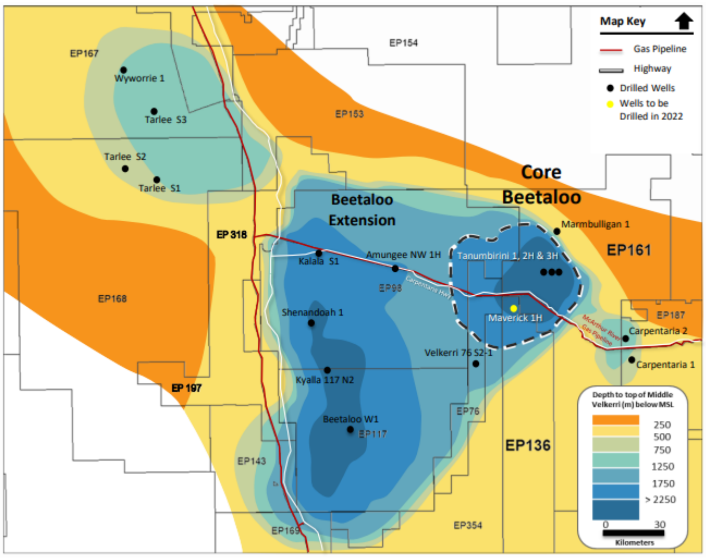
Appendix 2 – Tamboran Resources licenses

Figure 16 – TBN Licenses



Source: Company.

Figure 17 – TBN License Location

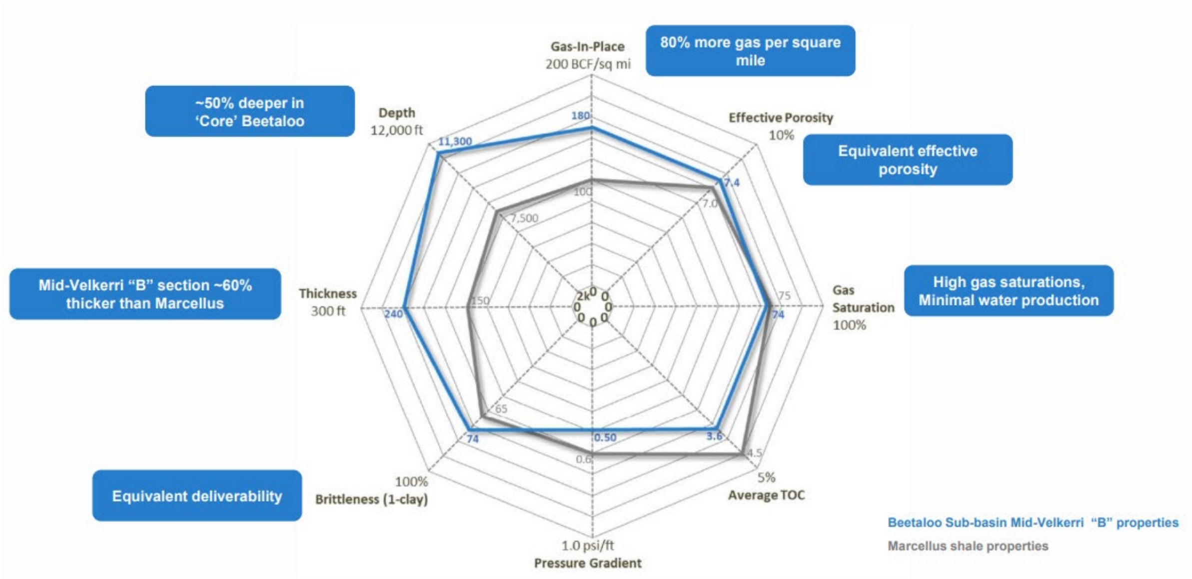


- >31 TCF total net prospective resources in Beetaloo Sub-basin depocenter position (~3,000-metre depth).
- Mid-Velkerri “B” shale is thickest, with limited faulting and superior reservoir qualities.
- **Significant de-risking of ‘Core’ Beetaloo area in last six months.**
- Three successful wells drilled:
  - Tanumbirini 2H/3H (Santos/Tamboran).
  - 76 S2-1 (Origin/Falcon).

Source: Company.

Appendix 2 – Mid-Velkerri “B” compared to Marcellus shale

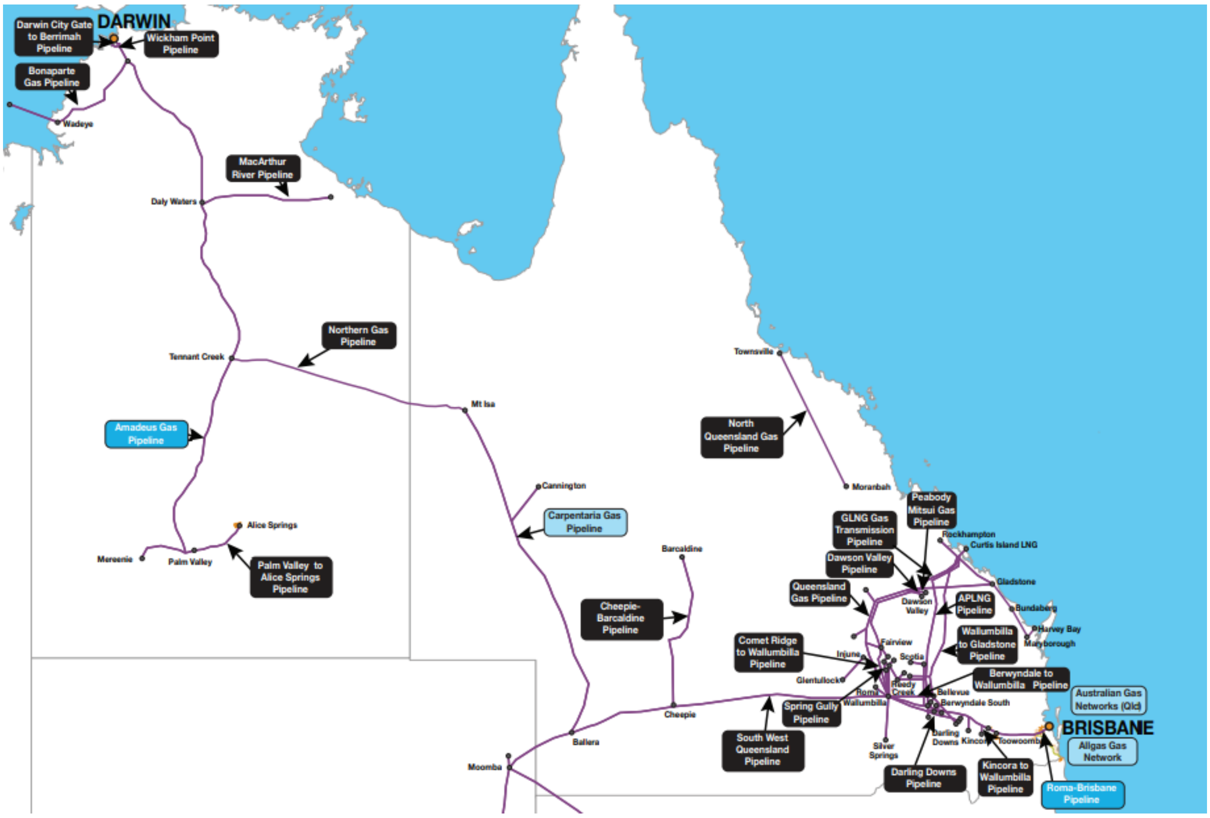
Figure 18 – High productivity potential with original gas in place equivalent to three stacked Marcellus shale play



Source: Company.

Appendix 4 - East Coast Australia Pipelines

Figure 19 – TBN will need access to Northern Gas, Carpentaria Gas and South-West Queensland pipelines

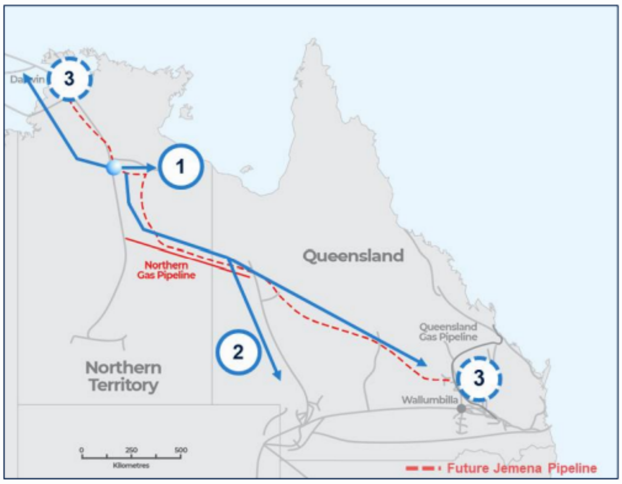


Source: AEMC

Appendix 5 – Key TBN assumptions for EP 136 development

Figure 20 – Phased approach to commercialising EP 136

Illustrative Jemena pipeline to commercialise Tamboran gas



The Jemena-Tamboran Joint Venture ("JTJV")

Jemena
bringing energy to life

In 2020, Tamboran and Jemena agreed on a detailed commercial framework to form a joint venture to build, own and operate long-term midstream gas infrastructure.

Phased approach to commercialise EP 136:

1. **Build ramp gas pipeline to NGP**
   Support appraisal and initial production volumes of Beetaloo gas.

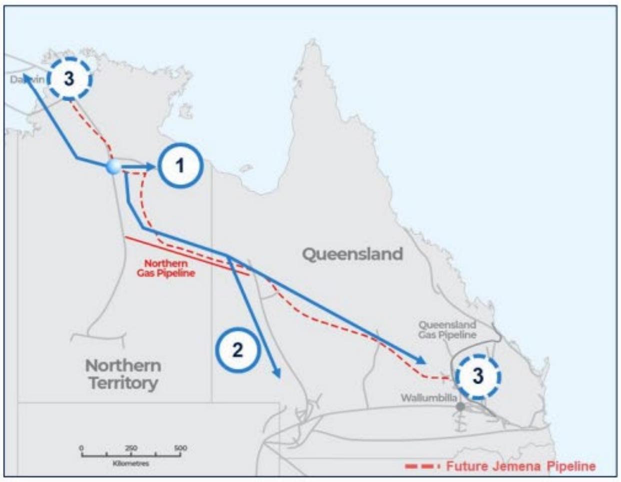
2. **Doubling capacity of NGP**
   Utilise existing infrastructure to deliver lowest cost gas to the East Coast from proposed ~100 TJ per day Maverick Pilot Development in 2025.

3. **LNG backfill opportunities**
   Full field development (+500 TJ per day) targeting potential LNG backfill markets in Darwin or Gladstone beyond 2030.

Source: Company

Figure 21 – TBN targeted full cycle cost to get gas from EP136 to Australian East Coast and or Darwin

Illustrative Jemena pipeline to commercialise Tamboran gas



Illustrative EP 136 total cost to market

	1	2	3	
	2023-2024	2025	2028+ Domestic & LNG backfill	
Cost Breakdown	Local NT	SE existing infra	Wallumbilla	Ichthys / Darwin LNG
Upstream Cost[1] A$/GJ	~$4.50	~$2.00 - $3.00	~$2.00 or less	
Northern Territory via McArthur River Pipeline	~$0.50			
East Coast Existing infrastructure		~$4.00		
Ichthys / Darwin LNG via new Jemena pipeline (~1,000 TJ per day)				~$0.50
Wallumbilla via new Jemena pipeline (~1,000 TJ per day)			~$2.00	
Total (A$/GJ)	~$5.00	~$6.00 - 7.00	~$4.00	~$2.50

Source: Company

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