Now the biggest player in the Beetaloo

TBN has restated its proposed commercialisation program to supply gas from the Beetaloo Basin to the Australian east coast and global liquified natural gas (LNG) markets in a 2025-2030 timeframe.

The first goal is to prove up 0.7 trillion cubic feet (Tcf) of net 2P gas reserves and sanction a 100 tera joule (TJ) per day (gross) Amungee pilot development by the end of CY 2023.

By the end of CY 2025, TBN want to be producing 100 TJ/day from the pilot development and are targeting ~5.0 Tcf of net 2P gas reserves sourced from TBN's interest in the binding gas supply agreement (GSA) with Origin Energy (ORG) and a proposed 2.2 million tonne per annum (Mtpa) LNG tolling agreement or development opportunity.

Longer term, TBN want to be producing 1 billion cubic feet per day (Bcfd) (~390 peta joules (PJ) per annum) to backfill existing LNG plants or new greenfield plants by 2028-2030.

We can see the share price doubling in the next 6-9 months - TBN trading at $0.19/GJ of 2P+2C

Assuming an enterprise value (EV) to (2P+2C) multiple of $0.50/GJ, we can imply a December 2022 TBN valuation of $0.58. We believe the stock will rerate on the back of successful flow testing at the Amungee 2 Horizontal (A2H) and A3H wells, forecast to be completed by mid to late CY 2023.

A bigger prize in the medium term

TBN believe that the successful completion of the planned five wells (Maverick 1 Vertical (M1V), already completed), A2H (currently being drilled), A3H, A4H and A5H by ~ March 2024 has the potential to deliver net ~2.9 Tcf of 2C contingent resource. Assuming TBN then trades in line with comparable Australian oil and gas EV/(2P+2C) resource multiples of ~$0.50/GJ we can derive a valuation of $0.94 per share.

We highlight that on this basis, if TBN traded at $0.75/GJ by March 2024, the implied valuation for TBN then would be $1.44.

Fully funded out to mid-2023

Based on the TBN's stated work program and our (and TBN's) assumed forecast expenditures we estimate that TBN is fully funded out to mid CY 2023. (See inside report (Page 5) for cash flow forecasts out to June 2024.

Valuation

We have a spot valuation of $0.58 per share for TBN (unchanged).

Please see inside report for risks associated with our TBN valuation and forecasts.

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$0.26
Market cap	A$368 m
Cash position	A$77 m (MST forecast December 2022)
Valuation (per share)	A$0.58 (Unchanged)

News Flow and Catalysts	
End 1Q CY 2023	Flow testing results from Amungee 2H
2Q/3Q CY 2023	Amungee 3H to be drilled, fracked and flow tested
Late CY 2023	Amungee 4H and 5H to be drilled, fracked and flow tested

TBN Share Price (A$)

Source: FactSet

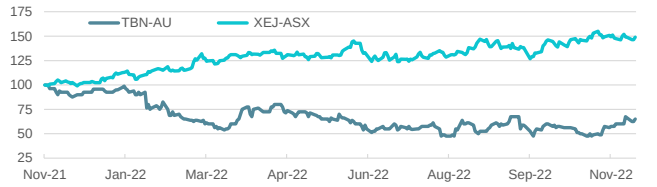
David Fraser
david.fraser@mstaccess.com.au

Figure 1 – Tamboran Resources Financial Data

Tamboran Resources — TBN-AU

Year end 30 June

MARKET DATA				
Price	**$**			**0.26**
52 week high / low	A$		0.40	0.19
Valuation	**A$**			**0.58**
Market capitalisation	A$m			368.2
Shares on issue (basic)	**m**			**1416.0**
Options	m			59.4
Shares on issue (diluted)	**m**			**1475.4**



INVESTMENT FUNDAMENTALS		FY21	FY22	FY23E	FY24E
EPS reported	¢	(19.2)	(1.5)	(1.0)	(1.8)
EPS underlying	**¢**	**(19.2)**	**(1.5)**	**(1.0)**	**(1.8)**
P/E reported	**x**	**(1.8)**	**(14.4)**	**(25.7)**	**(14.2)**
P/E underlying	**x**	**(1.8)**	**(14.4)**	**(25.7)**	**(14.2)**
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	104.4	128.6	241.0	286.3
Net Tangible Assets per share	¢	16.0	17.2	17.0	17.9
Free cash flow	$m	(21.8)	(67.2)	(126.1)	(102.2)
Free cash flow yield	%	(50.3)	(43.1)	(40.1)	(26.0)
Price to Free cash flow	x	(2.0)	(2.3)	(2.5)	(3.8)
Year end shares	**m**	**653**	**747**	**1,416**	**1,604**
Average shares on issue	m	124	708	1,209	1,510
Year end / Spot share price	$	0.35	0.22	0.26	0.26
Market cap (Y/E / Spot)	$m	229	164	368	417
Net debt /(cash)	**$m**	**(63)**	**(27)**	**(35)**	**(5)**
Enterprise value	**$m**	**165**	**138**	**333**	**412**
EV/EBITDAX	**x**	**n/m**	**n/m**	**n/m**	**n/m**
Gearing (net debt / EBITDAX)	**x**	**n/m**	**n/m**	**n/m**	**n/m**

PROFIT AND LOSS		FY21	FY22	FY23E	FY24E
Sales	**$m**	**0.0**	**0.0**	**0.0**	**0.0**
Other income	$m	2.5	0.6	7.5	0.0
Operating costs	$m	(18.1)	(10.8)	(19.1)	(26.9)
EBITDAX	**$m**	**(15.6)**	**(10.2)**	**(11.6)**	**(26.9)**
Exploration & evaluation expensed	$m	0.0	0.0	0.0	0.0
EBITDA	**$m**	**(15.6)**	**(10.2)**	**(11.6)**	**(26.9)**
Depreciation & Amortisation	$m	(0.4)	(0.6)	(0.7)	(0.8)
EBIT	**$m**	**(16.0)**	**(10.7)**	**(12.2)**	**(27.8)**
Net interest	$m	(7.8)	(0.1)	0.0	0.0
Pretax Profit	**$m**	**(23.8)**	**(10.8)**	**(12.2)**	**(27.7)**
Tax expense	$m	0.0	0.0	0.0	0.0
NPAT	**$m**	**(23.8)**	**(10.8)**	**(12.2)**	**(27.7)**

BALANCE SHEET		FY21	FY22	FY23E	FY24E
Cash	$m	63.1	26.8	35.4	4.8
Receivables	$m	0.4	2.9	2.9	2.9
Other	$m	0.0	1.0	1.0	1.0
Current assets	$m	**63.6**	**30.7**	**39.3**	**8.7**
Exploration & Evaluation	$m	46.6	85.0	208.9	285.9
Oil and Gas assets	$m	0.7	16.4	(3.5)	(4.3)
Right of use assets	$m	1.4	1.0	0.7	0.5
Other	$m	0.3	1.0	1.0	1.0
Non current assets	$m	**49.0**	**103.4**	**207.1**	**283.1**
Total Assets	**$m**	**112.6**	**134.1**	**246.4**	**291.8**
Accounts Payable	$m	5.7	3.9	4.0	4.2
Borrowings	$m	0.0	0.0	0.0	0.0
Other	$m	1.3	0.8	0.7	0.7
Current liabilities	$m	**7.0**	**4.6**	**4.8**	**5.0**
Borrowings	$m	0.0	0.0	0.0	0.0
Provisions	$m	1.1	0.7	0.5	0.4
Other	$m	0.1	0.2	0.2	0.2
Non current liabilities	$m	**1.2**	**0.9**	**0.7**	**0.6**
Total Liabilities	**$m**	**8.2**	**5.5**	**5.5**	**5.5**
Equity	$m	183.9	217.4	357.4	432.4
Retained earnings	$m	(88.1)	(98.9)	(111.1)	(138.8)
Reserves / Other	$m	8.6	10.1	(5.4)	(7.3)
Total equity	**$m**	**104.4**	**128.6**	**241.0**	**286.3**

Licenses	TBN Ownership	Partners
EP 76	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 98	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 117	38.75%	Sheffield 38.75%, Falcon Oil 22.5%
EP 136	100.0%	
EP 161	25.0%	Santos 75%
EP 143	100.0%	
EP(A) 197	100.0%	

RESERVES & RESOURCES			
Prospective Gas Reources net to TBN (Tcf)	**Low (1U)**	**Best (2U)**	**High (3U)**
Lower Kyalla	0	0	1
Mid Velkerri C	20	36	75
Mid Velkerri B	52	86	176
Mid Velkerri A	13	26	60
Total (Tcf)	**86**	**148**	**312**
Contingent 2C Gas Reources net to TBN (Bcf)	**Low (1C)**	**Best (2C)**	**High (3C)**
Lower Kyalla	0	0	0
Mid Velkerri C	133	590	1,342
Mid Velkerri B	202	897	2,039
Mid Velkerri A	0	0	0
Total (Bcf)	**335**	**1,488**	**3,381**
Total (PJ)	**355**	**1,577**	**3,584**

CASH FLOW		FY21	FY22	FY23E	FY24E
EBITDAX	$m	**(15.6)**	**(10.2)**	**(11.6)**	**(26.9)**
Working Capital / Other	$m	2.5	(2.3)	7.5	0.0
Net interest	$m	(0.1)	(0.0)	(0.0)	0.0
Tax paid	$m	0.0	0.0	0.0	0.0
Operating cash flow	**$m**	**(8.6)**	**(11.1)**	**(10.0)**	**(25.2)**
Exploration & development	$m	(13.2)	(54.9)	(86.4)	(77.0)
Acquisitions	$m	0.0	(1.2)	(60.0)	0.0
Divestments	$m	0.0	0.0	41.7	0.0
Other	$m	0.0	(0.0)	(11.4)	0.0
Investing cash flow	**$m**	**(13.2)**	**(56.1)**	**(116.2)**	**(77.0)**
Change in Equity	$m	83.0	35.0	140.0	75.0
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	$m	(3.7)	(3.8)	(5.4)	(3.4)
Financing cash flow	**$m**	**79.3**	**31.1**	**134.6**	**71.6**
FX	$m	0.0	(0.2)	0.1	0.0
Change in Cash	$m	57.5	(36.3)	8.6	(30.6)
Cash year end	**$m**	**63.1**	**26.8**	**35.4**	**4.8**

Spot Valuation				
2C plus 2P (PJ)	1,577	1,577	1,577	1,577
Resource multiple A$ / (2P+2C) (GJ)	**0.25**	**0.50**	**0.75**	**1.00**
Reserve Value	391	785	1,179	1,574
Net cash (MSTe Dec 2022)	77	77	77	77
Equity valuation	**468**	**862**	**1,256**	**1,651**
Share value per diluted share	**0.32**	**0.58**	**0.85**	**1.12**

Source: MST Access, Company data

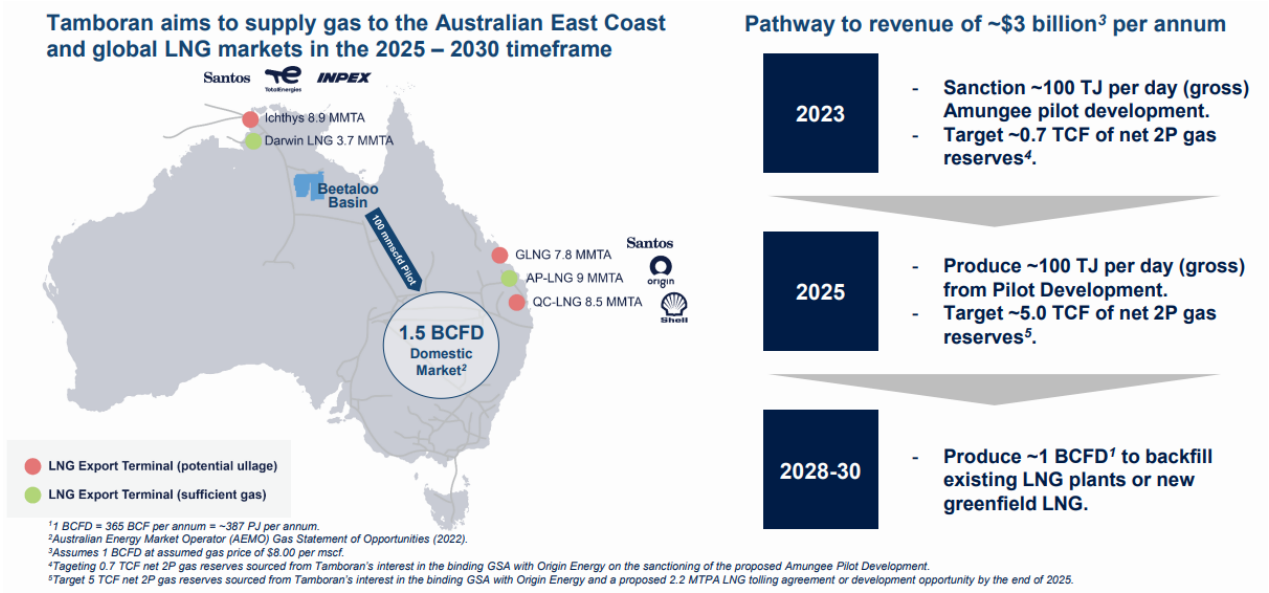
Tamboran Resources Investment Thesis

TBN has a stated prospective 2U resource (net to TBN) of 147 Tcf and a 2C contingent resource of ~1.5 Tcf in the Beetaloo Basin in Northern Australia. TBN is looking to develop the assets so as to target the undersupplied Australian LNG markets and domestic gas markets.

We forecast that TBN has funding available to meet its current forecast work program until the middle of CY 2023. At that stage it will need to seek new funding via equity, debt (reserve backed lending), pre-paid gas sales or asset sell downs and or farm outs. Our financial forecasts (Figure 1) assume equity is issued in CY2023 to progress the program.

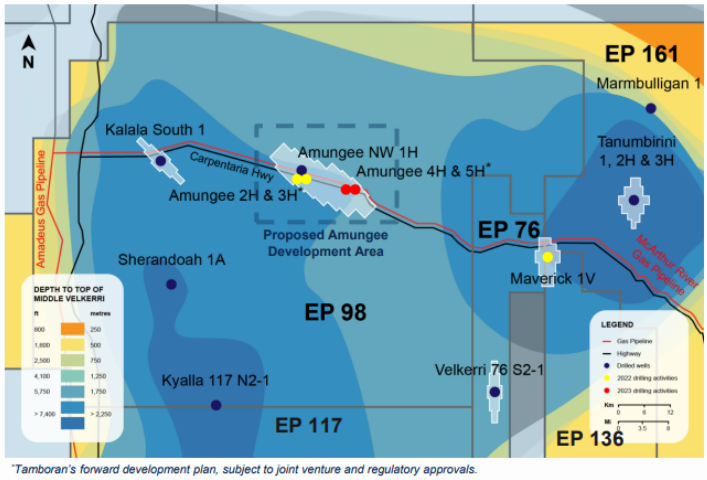
Valuation: We have a spot valuation of $0.58 per share for TBN (see Pg 7 for methodology).

Figure 2 – Target is to become a 1 Bcfd producer to backfill existing and new LNG plants



Source: Company

Figure 3 – Pathway to ~5.0 Tcf of net 2P gas reserves by the end of 2025 with first production in 2025



*Tamboran's forward development plan, subject to joint venture and regulatory approvals.

Five wells planned over the next 18 months have potential to deliver net 2C contingent gas resources of ~2.9 TCF¹.

- **2022: Drill Maverick 1V (EP 136) & Amungee 2H/3H (EP 98)**
  - Maverick 1 to be drilled as a vertical well to prioritise capital for accelerating commercial production from proposed Amungee Pilot development.
  - Potential to increase total net 2C contingent gas resources to ~2.0 TCF¹ across Tamboran's Beetaloo Basin assets.
- **2023: Drill, fracture stimulate and flow test two horizontal wells in EP 98²**
  - Well locations strategically positioned adjacent to the existing McArthur River Gas Pipeline infrastructure.
  - Targeting potential net 2C contingent gas resources of ~2.9 TCF from Tamboran's Beetaloo permits.
  - **Potential to book ~0.7 TCF 2P gas reserves** supported by the 10-year, ~100 TJ per day (36.5 PJ per annum³) GSA with Origin Energy and sanctioning of the proposed Amungee Pilot Development in EP 98.
- **Targeting to book ~5.0 TCF net 2P gas reserves through a proposed 2.2 MTPA⁴ LNG tolling agreement or development by the end of 2025.**
- **All horizontal wells are expected to be used as producers, targeting to deliver gas volumes into the domestic market by end-2025.**

¹Maturation Study provided by NSAI on 14 September 2022 shows potential net 2C contingent gas resources matured through successful drilling of four Amungee wells in EP 98 and Maverick 1V in EP 136.
²Subject to successful completion of 2022 work program.
³36.5 PJ per annum = 34.6 BCF per annum (~18.25 PJ per annum = 17.2 BCF per annum net to Tamboran).
⁴2.2 MTPA over 20-years required reserves of ~2 TCF (~2,120 PJ).

Source: Company

Capital raise and transformational acquisition

TBN has recently entered into a number of transactions that has materially lifted its prospective and contingent resource base.

Key points to note are:

- **TBN and Bryan Sheffield agreed to jointly (50% each) acquire Origin Energy's (ORG) 77.5 % interest in three Beetaloo Basin permits (EP 98, 117 and 76)** through a joint venture (JV) for an upfront cash consideration of $60 m plus a future production revenue royalty of 5.5% to ORG. **Falcon Oil and Gas (FO)** hold the remaining 22.5% in the permits.
- Post the acquisition, TBN has:

  - become the largest acreage holder in the Beetaloo Basin with ~1.9 million net prospective acres (up 445% from 0.35 million acres

  - **increased its net 2C contingent gas resources 270% to ~1.5 Tcf from 0.4 Tcf, and**

  - **increased its net 2U prospective gas resources 370% to ~147 Tcf from 31 Tcf.**
- The JV entered into a binding 10-year **Gas Sales Agreement (GSA)** for up to 36.5 PJ per annum (100 TJ/day) (18.3 PJ per annum net to Tamboran) with ORG who will have the option to acquire at least an additional 200 TJ per day for 10-years from the JV interest in the permits. We guesstimate that the contract will be oil linked. If we assumed a 10% slope against a Brent oil price benchmark, at current prices and exchange rates (Brent spot US$84/bbl and AUDUSD of 0.68), **the potential gas contract price would be currently ~A$11.70/GJ** at Ballera.
- **TBN has committed to solely fund the remaining ORG Stage 3 farm-in commitments** that were contracted with Falcon Oil and Gas (FO), which includes the drilling of two horizontal wells, at an estimated cost of $80 m, and back costs to the effective date of 1 July 2022.
- FO has also earned an additional $30m carry on future well costs as part of the "binding letter of intent with TBN and Sheffield. Thus, TBN and Sheffield will fund an additional $6.75m of well costs, or $3.4m each
- **Equity capital of ~140m at $0.21 per share** has been raised via institutional and private placements and a share purchase plan to fund the various transactions and program requirements.
- **Helmerich and Payne (H&P),** the largest onshore driller in the United States, invested $22 m in the placement. TBN has finalised a drilling contract with H&P for a super-spec FlexRig® (Rig 469) for a two-year term.

  The rig will mobilise into Australia for the TBN's 2023 proposed drilling campaign.

  As part of the strategic alliance, H&P will have the right of first refusal until 2033 to provide TBN all subsequent rigs required to accelerate TBN's 1 billion cubic feet per day (Bcfd) development plan at market rates.

  Once imported into Australia, H&P's super-spec FlexRig®, with more than 2,000 horsepower and one-million-pound hook load [1] will be one of Australia's most powerful onshore drilling rigs. Capable of drilling more than 4,000 metre horizontal sections within the Mid-Velkerri "B Shale", the rig is expected to support a material reduction in cost per unit of recoverable gas.
- TBN has granted a **2.3% overriding royalty interest (ORRI**) covering TBN's EP 136 (100%), EP 161 (25%), EP 98, EP 117 and EP143 (the ORG assets) (38.75%), EP 143 (100%) and EP 197 (100%) to **Sheffield interests** for a cash consideration of $22 m.

[1] Hook load is the sum total of all the downward forces pulling on the hook. In other words, the hook carries the drilling load; it is the actual weight of the drill string as measured from the surface. The hook load will therefore be at its maximum when all the weight attached to the hook is suspended freely in air with no support. During drilling, the drill string (drill pipe and other bottom hole assembly) will be immersed in the drilling fluid in the hole. In so doing, some of this load will be transferred to the drilling fluid, thereby reducing the hook load. In high angle wells (common these days), hook load also reduces due to friction as the drill string makes contact with or rests on one side of the borehole.

Forward work plan

Following the acquisition TBN has moved its attention away from EP 136 and is now focussing on EP 98. This follows a decision to prioritise the acceleration of booking 2P reserves and first commercial production from the proposed Amungee Pilot Development, which is supported by the recently signed 10-year GSA with Origin.

As a result, **Maverick 1H in EP 136** (100% funding by TBN), which was planned to have a 1,000m lateral drilled was changed to be a vertical well (M1V). This well has been completed (Target depth (TD) of 3,050m was reached in 18.3 days) with a total cost of ~$30m (well below the original forecast cost given the speed it was completed and the lack of the proposed fracks (20 fractures at $0.7m per frack saves $14m).

The forward plan for M1V is to acquire wireline logs and then to suspend the well and assess the potential to use data from the two Amungee wells to optimise a future 3,000 m horizontal section in the Maverick well, using the H&P super-spec FlexRig®, which is planned to be mobilised into Australia for the Company's 2023 proposed development drilling campaign.

The first of the two planned wells required under the farm-in commitments with FO, **Amungee 2 Horizontal (H)** was spudded on 10 November 2022. TBN will drill the vertical and build section to a depth of approximately 2,450 m, prior to drilling the 1,000 m horizontal section within the primary target of the Mid-Velkerri "B" Shale.

Following drilling, the A2H well is expected to commence a hydraulic fracture stimulation program (20 fracks over 1,000m) with a US style unconventional shale design in early CY 2023 with flow testing results by the end of the March 2023 quarter. The well is designed with 5-½ inch casing that allows for effective placement of proppant into the formation, optimising completion efficiency.

Both A2H and A3H are targeted to be used as producers with first production aimed for the end of CY 2025.

The **Amungee 3H** well is proposed to be drilled post the completion of A2H. Timing is dependent on where the team decides to locate the well. If it is drilled where ORG originally planned, it will likely be completed by mid-year using the rig that drilled A2H. If the TBN team decide to relocate the drill site, the well could potentially be drilled by the H&P rig forecast to arrive mid-year and thus well completion would slip into the second half of the calendar year (particularly as it is likely it would require new water bores to be drilled and six months of environmental water testing).

Once the two Amungee wells have been drilled, the funding of future work will be in line with the ownership levels; i.e. TBN will fund 38.75% going forward. Rather than the 100% required for the inherited FO farm in commitments and the 100% funding required if TBN continued on working in EP 136.

TBN is targeting initial flows of 5 mmscfd per 1,000m lateral from A2H and A3H.

TBN's forward work program envisaged five wells (See Figure 3) over the 18 months from September 2022; i.e to March 2024. Post M1V (completed), A2H (underway) and A3H, TBN plan to drill two additional wells **Amungee 4H and Amungee 5H.**

We note the four Amungee wells are strategically positioned adjacent to the existing McArthur River Gas pipeline infrastructure which could provide an early option to get gas to market before the proposed end of CY2025 forecast. (see Figure 3).

Given A4H and A5H are proposed to have 3,000m laterals with 50m fracture spacing (60 fracks) the well costs are forecast to be circa $50m-$55m per well; so a ~$43m funding cost for TBN for both wells (38.75% of $110m).

The question then is will FO participate given both wells will cost them ~$25m. If FO choose not to participate TBN could potentially have to fund 50% of the wells, or $55m.

Following the five well program, if successful, it is expected to allow TBN to sanction the proposed Amungee Pilot Development by the end of CY 2023.

Cash flow forecasts and near-term funding requirements

We table below a simple summary of what we believe are TBN's near term cash flows reflecting the stated plans at the recent equity raise.

Key forecasts and assumptions going down the cash flow statement are:

- Staff and administration costs to step up following the acquisition of the ORG assets reflecting the ORG staff coming on board to TBN.
- TBN to receive the remainder of the $7.5m grant from the Beetaloo Cooperative Drilling Program for M1V.
- $2m expenditure on plant and equipment in the March 2023 quarter represents the final payment for the three drill rigs acquired in early CY 2022. Given the new relationship with H&P, these rigs will now not be required, and we forecast will sold for ~$30m (timing unknown but we have assumed in the June 2023 quarter).
- As per the FY22 annual report TBN has a $2.4m capital commitment by the end of CY 2022 to maintain its interest in EP 161. Given the land access difficulties encountered with Rallen over the last year and the inability to undertake any activity, the commitments are delayed. Given the materiality (lack of) we have included here but are likely to be expensed in CY 2023 or later. We have assumed $5m expenditure spread over CY 2023 to maintain the interest in EP 161.

Figure 4 – Forecast Tamboran Resources cash flows out to June 2024

FY (A$m)	1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24
CY (A$m)	Sep-22	Dec-22	Mar-23	Jun-23	Sep-23	Dec-23	Mar-24	Jun-24
Receipt from customers								
Operating costs								
Staff costs	(1.2)	(1.8)	(2.5)	(2.6)	(2.8)	(2.9)	(3.0)	(3.2)
Admin and corporate costs	(1.4)	(2.1)	(2.8)	(2.9)	(3.1)	(3.2)	(3.4)	(3.6)
Receipt from government grants		7.5						
Net interest	(0.0)							
Net Operating Cash Flow	**(2.6)**	**3.5**	**(5.3)**	**(5.6)**	**(5.8)**	**(6.1)**	**(6.4)**	**(6.8)**
Net proceeds / (payment) for PPE	(8.8)	(2.0)		30.0				
TBN's share of EP161 costs (25%)			(1.3)	(1.3)	(1.3)	(1.3)		
TBN's share of EP136 costs (100%)	(9.3)	(15.0)	(2.5)	(2.5)	(2.5)	(2.5)		
TBN's share of EP98 / 117 / 76 costs (38.75%)	(7.3)	(25.0)	(15.0)	(21.5)	(21.5)	(21.5)	(21.5)	
Evaluation / Other			(2.5)	(2.5)	(2.5)	(2.5)		
Royalty reduction				(11.4)				
Acquisitions		(60.0)						
Divestments	(10.3)	52.0						
Net Investing Cash Flow	**(35.7)**	**(50.0)**	**(21.3)**	**(9.2)**	**(27.8)**	**(27.8)**	**(21.5)**	**0.0**
Equity raised	39.2	100.8			75.0			
Debt & Equity raise costs	(0.9)	(4.1)			(3.0)			
Lease liabilty / Other	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Financing Cash Flow	**38.2**	**96.6**	**(0.1)**	**(0.1)**	**71.9**	**(0.1)**	**(0.1)**	**(0.1)**
Movement in cash	**(0.2)**	**50.2**	**(26.6)**	**(14.8)**	**38.3**	**(34.0)**	**(28.0)**	**(6.9)**
Opening Cash	26.8	26.7	76.9	50.2	35.4	73.7	39.7	11.7
Closing Cash	**26.7**	**76.9**	**50.2**	**35.4**	**73.7**	**39.7**	**11.7**	**4.8**

Source: Company, MST

- The completion of M1V in EP 136 in the December 2022 quarter we forecast at ~$15m.
- As per the FY22 annual report, TBN also has a commitment to re-enter the vertical well (M1V), side track to drill a horizontal well, fracture and test the well and "perform the assessment of petroleum resources potential" with a minimum expenditure of $28.5m by 31 December 2023 to comply with the work program conditions of Year 5 of the EP 136 Exploration Permit. Given the land access was challenged in court, we believe TBN will likely be able to secure a delay in this funding requirement. For the purposes of the exercise below, we have assumed $10m of

expenditure in EP 136 spread over the CY 2023 year until we get further clarity. We believe TBN's focus will now be on EP 98.

- TBN is committed to fund 100% of A2H and A3H's ($80m) as part of the remaining ORG Stage 3 farm-in commitments that were contracted with Falcon Oil and Gas (FO). We have assumed $25m of A2H occurs in the December quarter and $15m (fracturing and flow testing of the well) in the March 2023 quarter.
- We note in FO's stock exchange release (11 October 2022), FO has earned an additional $30m carry on future well costs as part of the "binding letter of intent with TBN and Sheffield. Thus, TBN and Sheffield will fund an additional $6.75m of well costs or $3.4m each.
- The remaining Amungee wells expenditure we assume totals ~$86m. $40m for A3H (100% funded by TBN), $43m for A4H and A5H (TBN's share 38.75% of two wells at $55m per well), and the additional $3.4m carry to FO noted above. We have assumed the wells are completed by the end of the March 2024 quarter (as per TBN plan) and expenditure is spread evenly over the four quarters including the June 2023 quarter. NB: If Falcon Oil and Gas is unable to fund its 22.5% share of the $110m well program, TBN and Sheffield may be up for $55m each versus the $46m we have assumed.
- We assume a front-end engineering and design (FEED) study is completed over CY2023 for the Amungee Pilot Development at a cost of $10m (spread evenly over the year).
- We have assumed TBN exercises its rights to reduce the overriding royalty interests (ORRI's) payable to Bayless (reduction from 4% to 2% at a cost US$7m) and Petrohunter's (reduction from 2% to 1% at a cost of US$1m) due to be paid by 1 July 2023. The forecast cost of A$11.4m potentially could be funded with scrip but we have assumed it is cash expensed at this stage.
- Acquisition in the December quarter is the purchase of ORG's 77.5 % interest in the three Beetaloo Basin permits (EP 98, 117 and 76) through a joint venture (JV) for an upfront cash consideration of $60m.
- Divestment proceeds of $52m to be received in the December quarter representing the sale of 38.75% of the ORG's 77.5 % interest to Sheffield for $30m and the sale of an ORRI on TBN's Beetaloo permits to Sheffield for $22m.
- In the December quarter the remaining equity contribution from the raise will be received ($140m less $39m already received in the September quarter) less transactions costs of ~$3.4m.

Thus, based on our forecasts, as at June 2023, TBN will have cash available of ~$35m but will require new funding before the end of the September 2023 quarter.

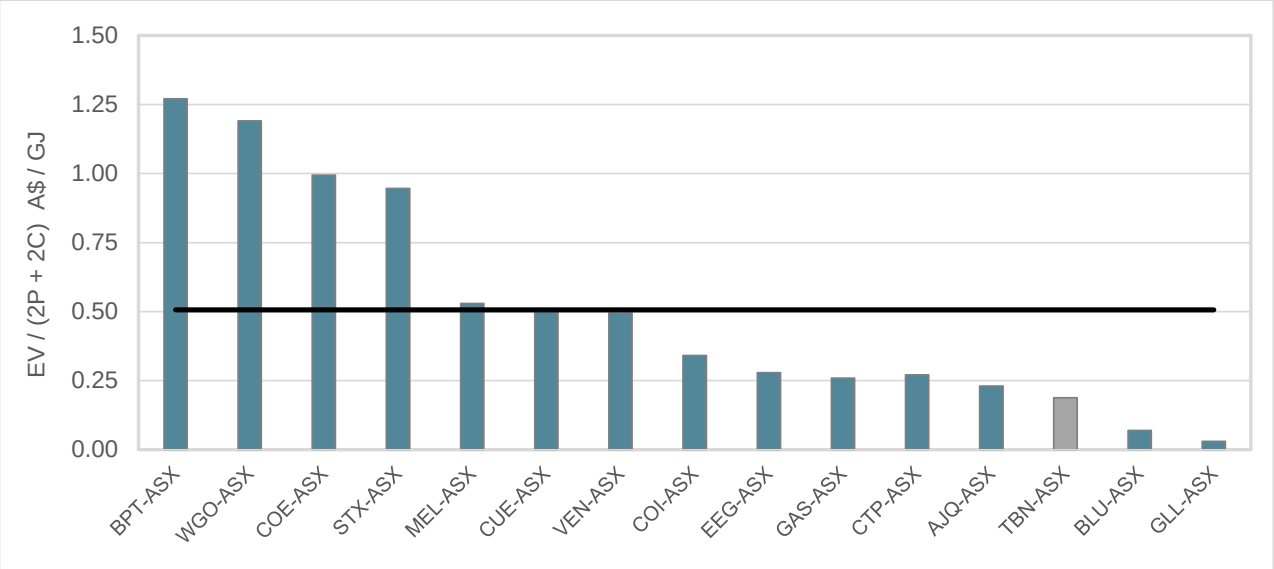
Clearly if TBN is unable to realise $30m for the rigs we believe will be sold, funding may be required sooner.

Valuation demonstrates material share price upside potential

We derive a spot valuation for TBN of $0.58 per share based on a EV/(2P+2C) resource multiple of A$0.50/GJ.

See table below for the oil and gas comparable companies EV multiples listed in Australia. The average multiple is ~$0.50/GJ.

Figure 5 – Peer comparisons on a 2P+2C basis (A$/GJ) – Average ~$0.50/GJ



Source: MST Access. FactSet (Prices at 1 December 2022), Company data

We then value TBN's net 1,577 PJ 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 5) and add our forecast 31 December net cash position to get a spot equity value for TBN.

We then divide by the forecast diluted shares on issue (1,475m) as at 31 December 2022.

Figure 6 – Spot Valuation (31 December 2022) based on different EV/(2P + 2C) multiples ($/GJ))

Spot Valuation				
2C plus 2P (Bcf)	1,488	1,488	1,488	1,488
2C plus 2P (PJ)	1,577	1,577	1,577	1,577
Resource multiple A$ / (2P+2C) (GJ)	**0.25**	**0.50**	**0.75**	**1.00**
Reserve Value	391	785	1,179	1,574
Net cash (MSTe Dec 2022)	77	77	77	77
Equity valuation	**468**	**862**	**1,256**	**1,651**
Share value per diluted share	**0.32**	**0.58**	**0.85**	**1.12**

Source: MST Access.

As noted earlier, TBN is targeting a net 2C contingent gas resource of 2.9 Tcf by the end of March 2024.

On the same basis as above, we derive TBN valuations on different EV/(2P+2C) resource multiples.

Note: Our forecast diluted shares on issue lifts from ~1,475m to ~1,604m given we forecast TBN will need to issue more equity in CY2023 to progress its plans. (Assumed $75m raised at $0.40 per share).

Figure 7 – March 2024 valuation based on different EV/(2P + 2C) multiples ($/GJ))

TBN Dec 2023 Target				
2C plus 2P (Bcf)	2.9	2.9	2.9	2.9
2C plus 2P (PJ)	**3.1**	**3.1**	**3.1**	**3.1**
Resource multiple A$ / (2P+2C) (GJ)	**0.25**	**0.50**	**0.75**	**1.00**
Reserve Value	769	1537	2306	3074
Net cash (MSTe Dec 2022)	40	40	40	40
Equity valuation	**808**	**1577**	**2345**	**3114**
Forecast shares	1604	1604	1604	1604
Share value per diluted share	**$0.48**	**$0.96**	**$1.44**	**$1.92**

Source: MST Access.

We highlight that if TBN traded at $0.75/GJ by March 2024, the implied valuation for TBN then would be $1.44.

Risks

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

extent and quality of the resource vs. expectations,

financial risks such as funding,

plant construction and commissioning costs,

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,

Company-specific risks such as management issues,

relationships with business partners,

environmental and operational risks,

regulatory risks, and

macroeconomic risk.

Appendix 1 - Resources and Reserves

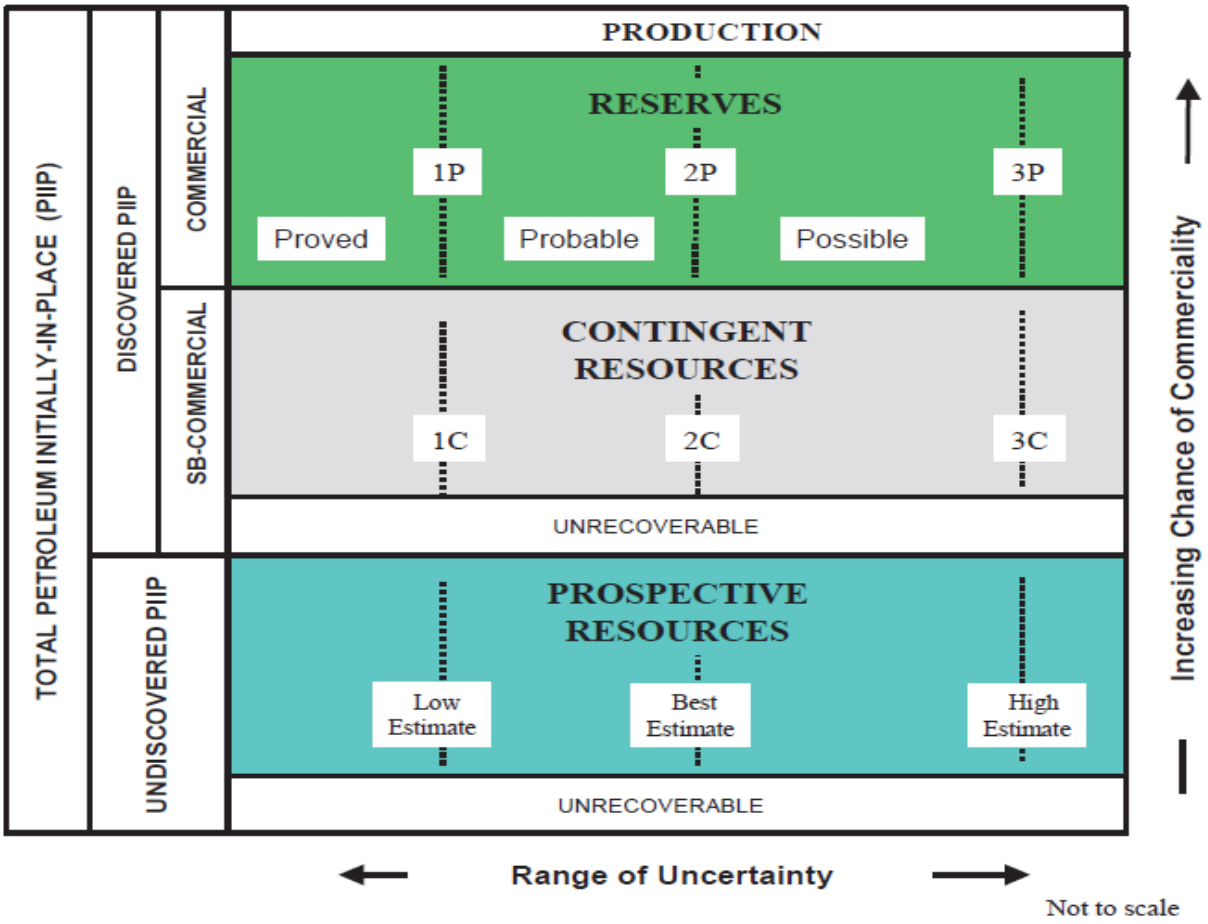
We note below the three categories into which estimated quantities of potentially recoverable petroleum can be placed: Prospective Resources, Contingent Resources and Reserves. Within each category, three estimates are designated to describe the range, with greater certainty at the low end and less certainty 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 8 – Resources and Reserves



Source: PRMS Resources Classification.

TBN Resources and Reserves

Figure 9 – Tamboran Resources and Reserves

EP136 (100%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla		0.2	
Mid Velkerri C		6.1	
Mid Velkerri B		9.7	
Mid Velkerri A		3.0	
Total (Tcf)	**11.1**	**19.1**	**40.0**

EP136 (100%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla			
Mid Velkerri C			
Mid Velkerri B			
Mid Velkerri A			
Total (Bcf)	**0**	**0**	**0**

EP161 (25%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla		0.2	
Mid Velkerri C		3.5	
Mid Velkerri B		6.5	
Mid Velkerri A		2.1	
Total (Tcf)	**7.1**	**12.4**	**26.5**

EP161 (25%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla		0	
Mid Velkerri C		159	
Mid Velkerri B		245	
Mid Velkerri A		0	
Total (Bcf)	**83**	**404**	**941**

EP98, EP117 & EP76 (38.75%)			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla			
Mid Velkerri C		26.0	
Mid Velkerri B		69.9	
Mid Velkerri A		20.4	
Total (Tcf)	**67.4**	**116.4**	**245.5**

EP98, EP117 & EP76 (38.75%)			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla			
Mid Velkerri C		431	
Mid Velkerri B		652	
Mid Velkerri A			
Total (Bcf)	**252**	**1083**	**2440**

EP143 (100%)
Prospective Gas Reources net to TBN (Tcf)
Total (Tcf)

EP143 (100%)
Contingent 2C Gas Reources net to TBN (Bcf)
Total (Bcf)

EP197 (100%)
Prospective Gas Reources net to TBN (Tcf)
Total (Tcf)

EP197 (100%)
Contingent 2C Gas Reources net to TBN (Bcf)
Total (Bcf)

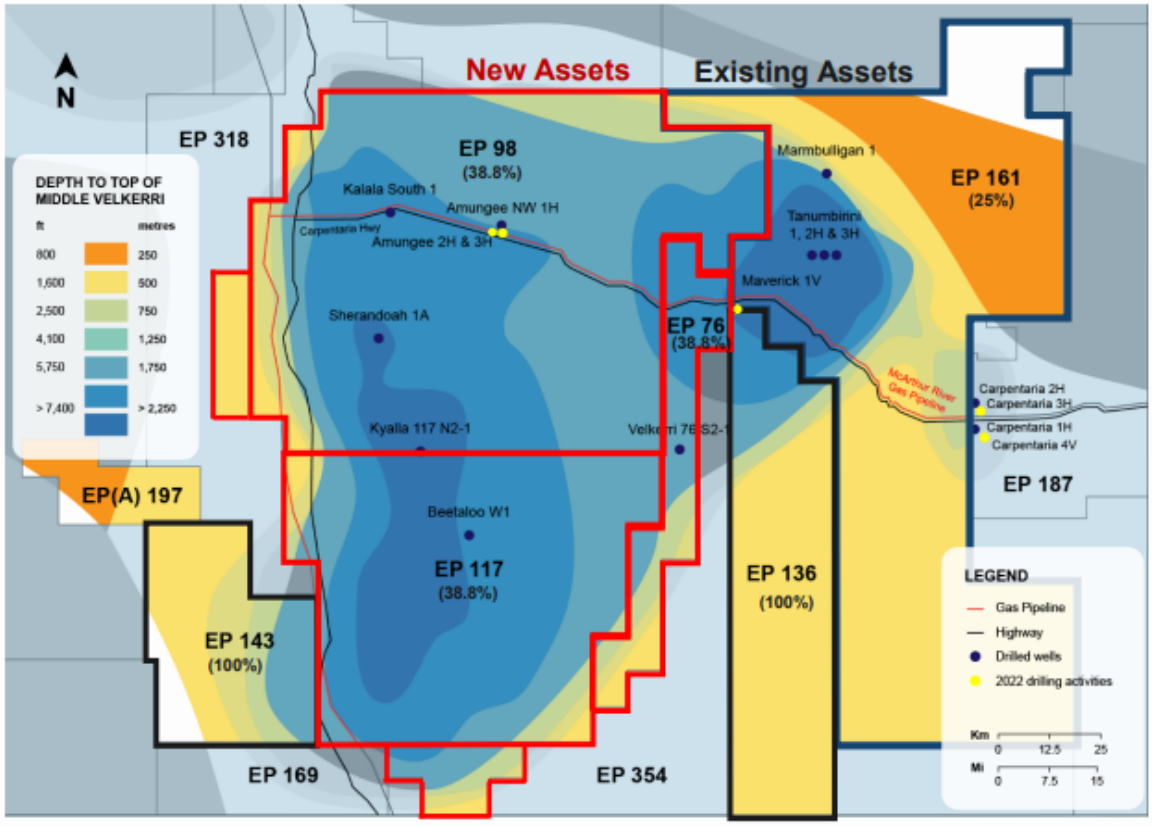
Total			
Prospective Gas Reources net to TBN (Tcf)			
	Low (1U)	**Best (2U)**	**High (3U)**
Lower Kyalla	0.2	0.5	1.5
Mid Velkerri C	20.5	35.6	75.2
Mid Velkerri B	51.8	86.1	175.7
Mid Velkerri A	13.2	25.6	59.7
Total (Tcf)	**85.6**	**147.8**	**312.0**

Total			
Contingent 2C Gas Reources net to TBN (Bcf)			
	Low (1C)	**Best (2C)**	**High (3C)**
Lower Kyalla	0	0	0
Mid Velkerri C	133	590	1342
Mid Velkerri B	202	897	2039
Mid Velkerri A	0	0	0
Total (Bcf)	**335**	**1488**	**3381**

Source: Company.

Appendix 2 – Tamboran Resources Licenses

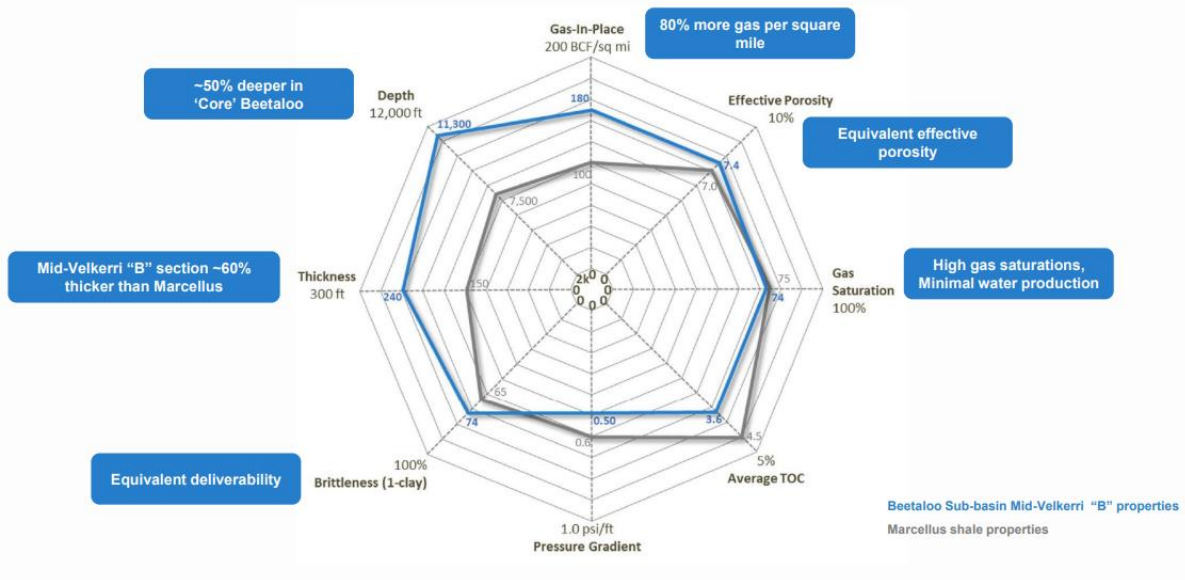
Figure 10 – TBN License Location



Source: Company.

Appendix 3 – Mid-Velkerri "B" compared to Marcellus shale

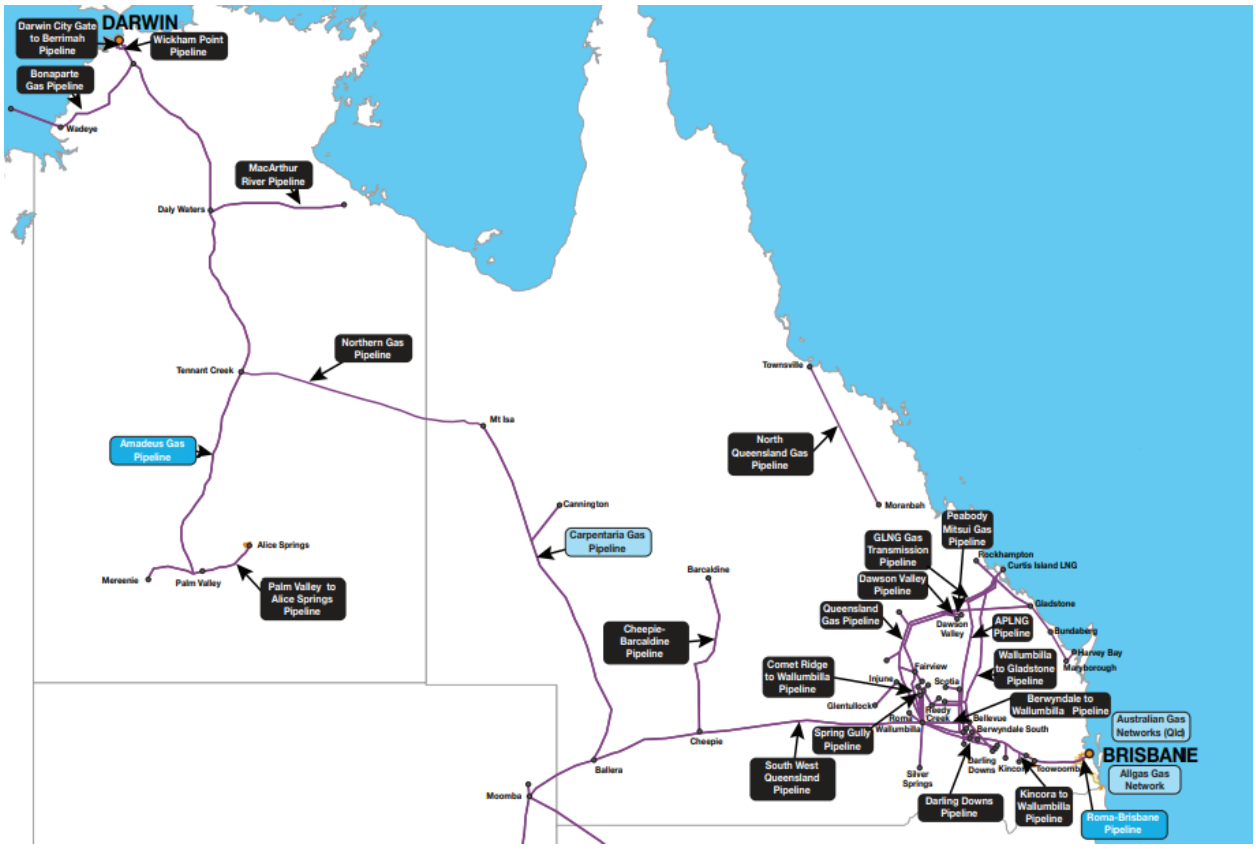
Figure 11 – High productivity potential with original gas in place equivalent to three stacked Marcellus shale play



Source: Company.

Appendix 4 - East Coast Australia Pipelines

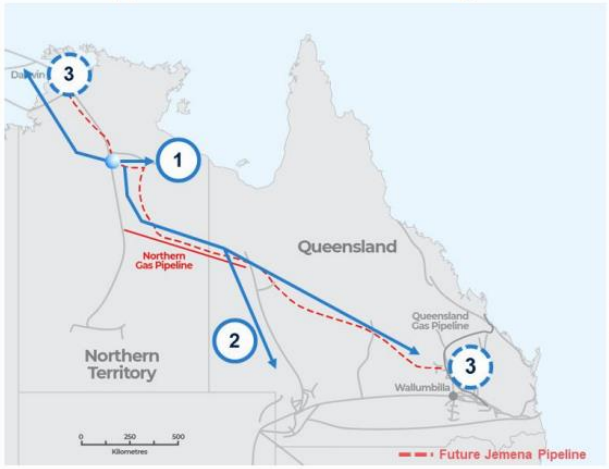
Figure 12 – TBN will need access to Northern Gas, Carpentaria Gas and South-West Queensland pipelines



Source: AEMC

Figure 13 – TBN targeted full cycle cost to get gas from EP136 to Australian East Coast and or Darwin

Illustrative pipeline to commercialise Beetaloo gas



	1	2	3	
	2023-2024	2025	2028+ Domestic & LNG backfill	
Cost Breakdown (US$ per mcf)	Local NT	SE existing infra	Wallumbilla	Ichthys / Darwin LNG
Upstream Cost[1] US$ per mcf	~$3.10	~$2.00	~$1.40 or less	
Northern Territory via McArthur River Pipeline	~$0.30			
East Coast Existing infrastructure		~$2.70		
Ichthys / Darwin LNG via new Jemena pipeline (~1 BCFD)				~$0.30
Wallumbilla via new Jemena pipeline (~1,000 BCFD)			~$1.40	
Total Sales (US$/mcf)	~$3.40	~$4.70	~$2.70	~$1.70
LNG Plant Liquefaction			~$2.50	~$2.50
LNG Shipping Australia to Japan			~$0.60	~$0.50
Total Delivered LNG (US$ per mcf)			~$5.80	~$4.70

[1]*Upstream costs include operating costs (fixed and variable) of ~A$1.00 per GJ and drilling capital expenditure (refer to slide 32).*

Source: Company

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