Tamboran Resources

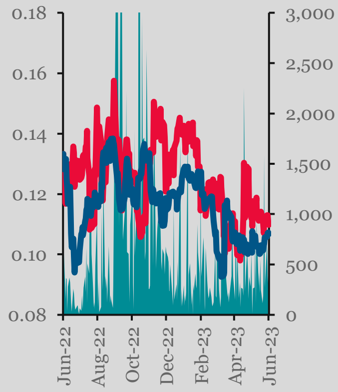
Capital raise to unlock Beetaloo Basin development

GICS Sector	Energy
Ticker	ASX:TBN
Market cap 27-Jun-23 (US$mm) (pre-equity raise)	170
Share price 27-Jun-23 (AUD $)	0.18

NAV summary (AUD c/sh)

Asset	Unrisked	Risked
Cash & other	5	5
EP 136	216	14
EP 98	187	42
EP 161	54	10
Total NAV	**462**	**71**

Source: H&P estimates



The cost of producing this material has been covered by Tamboran Resources as part of a contractual engagement with H&P Advisory Ltd.

TBN is raising up to A$71.4mm in new capital

TBN is raising A$58.2mm in new equity at $A0.18/sh plus a A$13.2mm convertible. It is positive to see strong funding support from various parties: Brian Sheffield (A$14.7mm), Helmrich & Payne (convertible), two US global energy funds (A$31mm), APA (A$10mm spending commitment) and Board and Management (A$2mm). Alongside existing funds this will provide ~A$100mm of liquidity, most (A$67mm) going towards SS1H and A3H wells planned for later this year. The financing will see TBN funded until Q1'24 after which this could be an attractive entry point for a farm-in partner. TBN would require a further A$50-70mm in 2024 to stimulate and test A3H, to drill the proposed SNV1 well and take the Flare Avoidance Project to early production. Other funding routes could be a royalty transaction, debt or a US listing. Combined with the September 2022 Origin acquisition, TBN will have raised ~A$275mm, which demonstrates the strong support in a tough market for E&P companies.

Series of announcements in strong push towards Beetaloo commercialisation

TBN has put out a series of announcements aimed at reaching commerciality in the Beetaloo. The A2H well has flowed gas, although not yet at commercial rates due to a “skin” inhibiting gas flow and TBN believes that it will be able to identify the cause of the skin and clean-up the well later in 2023, to be able to then provide IP30 flow rates. The JV does not think there is any reservoir issue. TBN has been progressing on many commercialisation fronts, and has signed a binding term sheet with APA to be the pipeline partner, with expectations of similar tariffs to previously estimated and APA committing A$10mm of spend. In addition, TBN has secured exclusivity for a mini-LNG facility, which could be deployed at Amungee. It has also been awarded a site for a proposed 6.6mpta (1bcf/d) NTLNG project in Darwin where the Government has committed A$1.5bn for common infrastructure and TBN has signed MOUs for two thirds of the export capacity with two of the leading LNG companies bp and Shell.

Marcellus type curves for T3H provide encouragement for SS1H exploration

The JV plans to drill the Shenandoah South 1H (SS1H) in EP 117 during Q3'23, where the Mid Velkerri "B Shale" is expected to be approximately 700m (30%) deeper than at A2H. The decision for the SS1H well location follows analysis of the Tanumbirini wells in the Santos-operated EP 161 permit, which showed Marcellus Basin production type-curves from the wells drilled in the area. TBN’s continuous Beetaloo acreage is equivalent to the entire Marcellus gas window acreage (>25 bcf/d). The Tanumbirini wells have been producing for the longest in the basin (>6 months) and provide solid data. T3H, demonstrated a 20-year expected ultimate recovery (EUR) of ~18.5 bcf (vs. our modelling at 15.5bcf) for a future proposed 3km development well. This demonstrates the enormous productivity within the deeper regions of the Beetaloo. The SS1H well IP30 flow test is planned for early 2024 and on success would allow the booking of initial 2C resource to be followed later in 2024 with the booking of 2P reserves associated with the pilot development. The A3H with the A2H could be potential development wells for the Flare Avoidance Project. There is also a well (SNV1) planned between Amungee and Shenandoah in 2023: TBN believes this trend could contain 17tcf of recoverable gas.

Valuation: cutting our risked NAV by 12% to factor in equity dilution

Our risked NAV of A$0.71/sh (factoring in the equity raise) is based on our long-term Brent forecast of US$70/bbl flat (implied L.T. Asian LNG price of US$10.5/mcf at 15% of Brent). On an unrisked basis we have a NAV of A$4.62/sh or ~25x upside for the development of 15tcf net to TBN. At an NPV10 of A$0.5/mcf, TBN’s market cap is pricing in a development of only 0.5tcf out of the ~150tcf of prospective unrisked net gas resource. TBN is looking to sanction a Pilot Development by the end of 2023/early 2024, targeting 700bcf of net 2P gas reserves (at a conservative Australian market 2P acquisition multiple of ~A$1/mcf NPV this would be worth A$700mm) with first production of 100mmcf/d aimed for end-2025 before it aims to add a further 5tcf of net 2P reserves. Towards the end of the decade, it aims to produce 1bcf/d of gas, which would generate US$3bn in revenue at US$8/mcf net.

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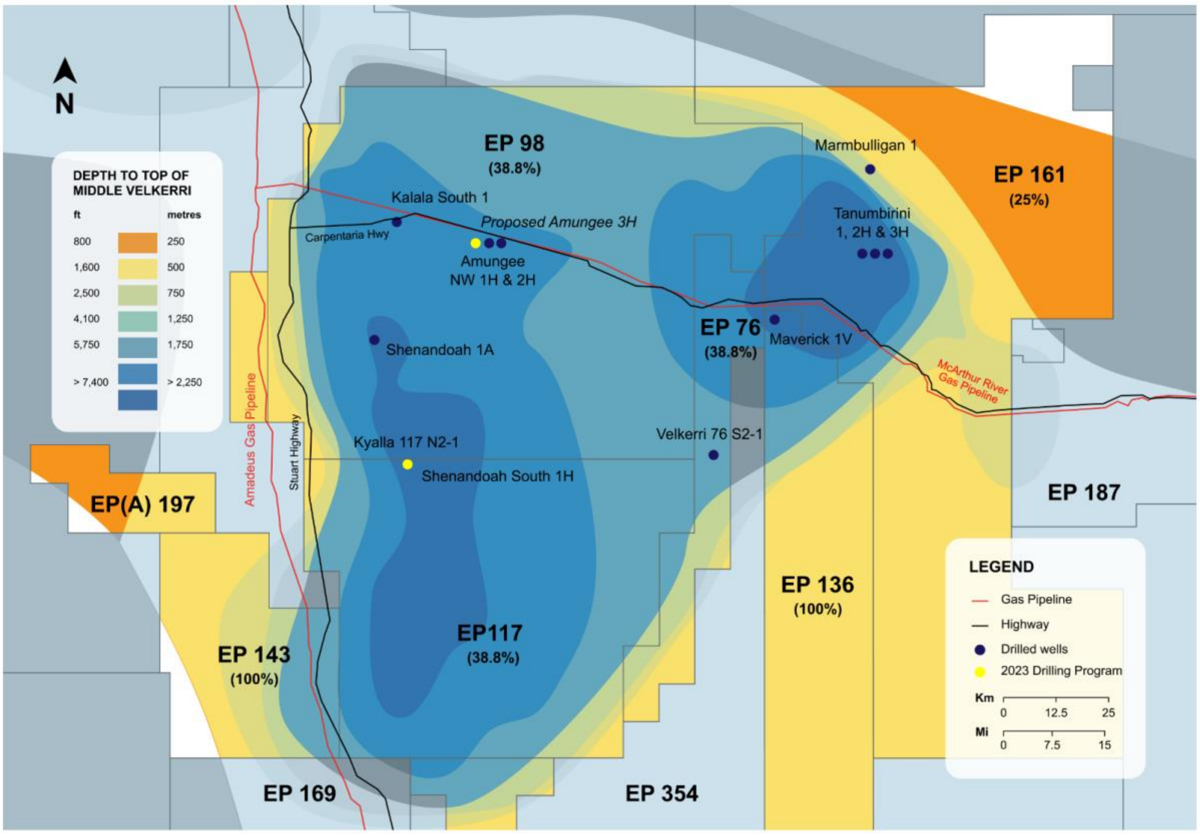
Investment case

Tamboran has the potential to be one of the largest global independent gas producers. It offers exposure into the positive pricing dynamics of Australia's gas market, which is becoming increasingly short, as existing resources are depleted. In turn, through Australia's LNG export capacity (largest globally), it offers exposure into global and especially Asian LNG markets, where prices are currently well above the expected full cycle break-even from the Beetaloo. Tamboran's exploration assets have huge gas potential (~150tcf of net recoverable prospective resources or >25bnboe) in one of the most promising shale gas basins globally, with the characteristics to match the best shale gas wells in the US. Given that this is a resource play with several wells drilled into it, there is very low risk in terms of there being large quantities of gas, but it is more a question of the economics and commerciality of producing the gas for which there have been promising results to date.

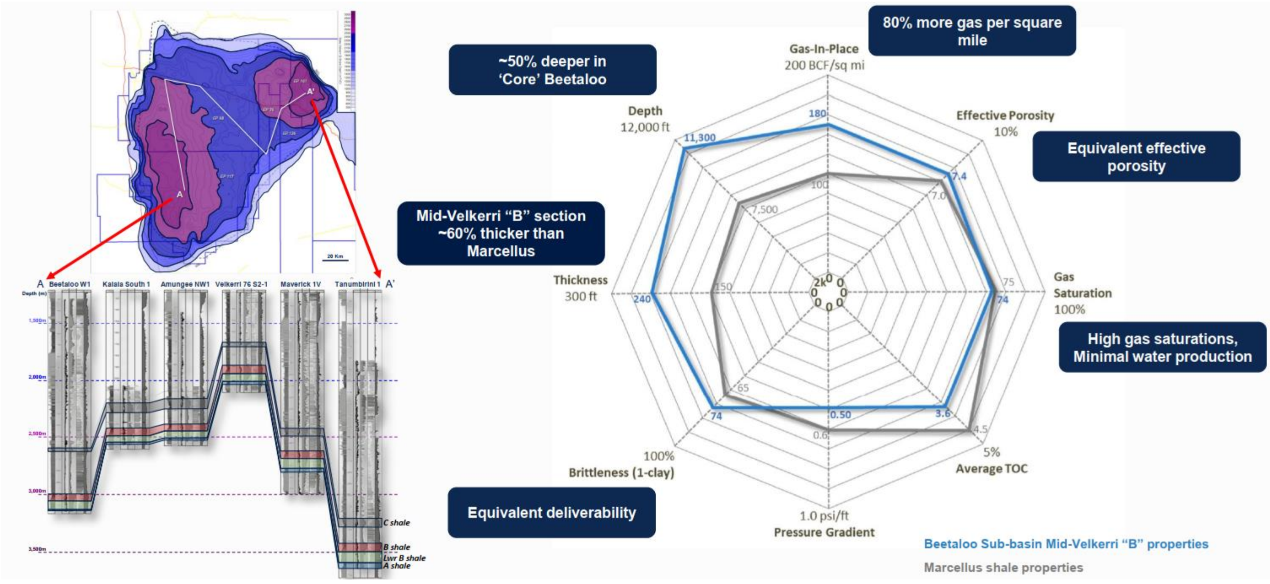
Tamboran's Beetaloo Basin asset location map



Source: Tamboran

The Beetaloo's properties and wells to date suggest excellent quality rock, allowing highly economic flow rates and recoveries per well with Tamboran's acreage located in the core of the basin. Crucially Tamboran has lined up multiple commercialisation pathways for the gas, which is key to value creation. It has an offtake agreement with Origin, is partnered with Santos, a major global LNG player with its own operated LNG facilities within range of the basin, has secured land for its own proposed Northern Territory LNG development, has MOUs covering two thirds of the capacity with Shell and bp and has signed a term sheet with APA as preferred pipeline partner to bring the gas to market. Tamboran's team has deep technical knowledge of US shale plays and track record of early-stage E&P success. Tamboran could produce some of the lowest cost gas in Australia and monetise it at premium pricing into Asia, as net zero emission LNG.

Rock qualities closely resemble the US' most prolific gas resource in the Marcellus Basin

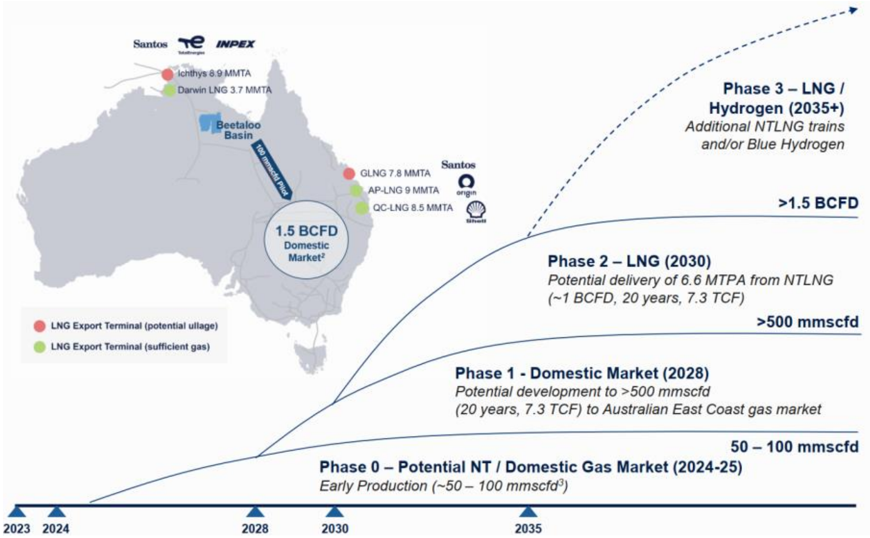


Source: Tamboran

All the elements in place for a successful shale development - We believe that the Beetaloo is well positioned to be successful given the geology and other commercial considerations. As the source rocks are much thicker than comparable US shale plays, there is potential for world-class resources, and the Beetaloo is considered by many to be the most prospective shale play in the world. Recent analysis of the Tanumbirini wells and company modelling confirm well recoveries in line with the prolific Marcellus Basin. Although unconventional oil and gas plays exist in many regions globally, very few have all the elements in place, in particular from a commercialisation perspective. As a result, outside of North America, the only material play to have been realised is the Vaca Muerta in Argentina. A successful full scale shale development requires conducive geology, adequate economic incentives, a transparent and consistent regulatory regime, available service/equipment capacity, infrastructure (or the means to build it), market access (and adequate pricing), and, last but not least, access to capital.

Management team are shale development specialists - Tamboran has a Board of Directors and management team that is akin to a sizeable US shale E&P company with deep technical knowledge and track record in early-stage E&P success. The Directors of Tamboran are recognized as pioneers in North American unconventional resources as well as unconventional (CBM) developments in Australia. Chairman Dick Stoneburner was the Founder of Petrohawk Energy, which developed one of the largest shale portfolios and was sold for US$12.1bn. Sheffield became one of the youngest billionaires in the energy business through his company Parsley Energy, which was founded in 2008 with shale assets in the core of the US Permian Basin and sold for a US$7bn valuation in 2022. Pat Elliot spotted the CBM play early in Queensland and sold Eastern Star Gas to Santos in 2011 for A$924mm. The Directors have led the initial development of multiple significant US oil and gas unconventional resource plays, including the Eagle Ford, Marcellus, Montney, Duvernay, Woodford, Fayetteville and Haynesville shales. Tamboran's operating team has been recruited from leading US E&P companies and has over 200 years of combined US unconventional experience. The team brings a wealth of knowledge to Tamboran, particularly relating to shale reservoir assessment and cutting-edge drilling and completion design technology.

Commercialisation of ~17 TCF (gross) resources via domestic sales and LNG export at Darwin



Source: Tamboran

Strategic infrastructure potential supports growth to 1-2bcf/d – TBN has signed an important deal with infrastructure company APA to build a 0.5bcf/d pipeline from the Beetaloo to access the East coast domestic gas and LNG export market. This has two major implications, first it means that Tamboran as a partner with APA will have access to significant gas that it can send down the pipeline, de-risking its route to market. Secondly there is significant value in gas infrastructure assets in Australia demonstrated by several deals such as Conoco purchasing an additional stake in APLNG and Tokyo Gas Australia selling to EIG. There is the potential for Tamboran to reach 100mmcf/d of net production by the end of 2025 and up to 1.5bcf/d by the end of the decade supplying the East Coast and/or an LNG project in the Darwin area.

Beetaloo Play has been de-risked with Tamboran in the core - TBN was an early mover in the Beetaloo basin, spotting the opportunity over a decade ago and obtaining acreage in the core of the basin: positioned right in the depocenter. It already has 1.5tcf of contingent resource that has been derisked by its and partners' drilling. The well data to date implies flow rates that are well above the commerciality threshold. Tanumbirini 3H (T3H) delivered a normalised rate of 5.2mmcf/d over 1,000m and T2H normalised at 3.3mmcf/d over 1,000m (lower as it had already produced 270mmcf before production tubing was installed). Amungee-NW1H well by Origin/Falcon suggested a flow rate of 5.5mmcf/d per 1,000m of lateral. In our base case development scenario, we assume 5.5mmcf/d per 1,000m and 15bcf recovery per well (EUR), which gives an NPV10 of ~A$0.5-0.7/mcf. This is lower than the 16.8-18.5bcf EUR from recent TBN modelling.

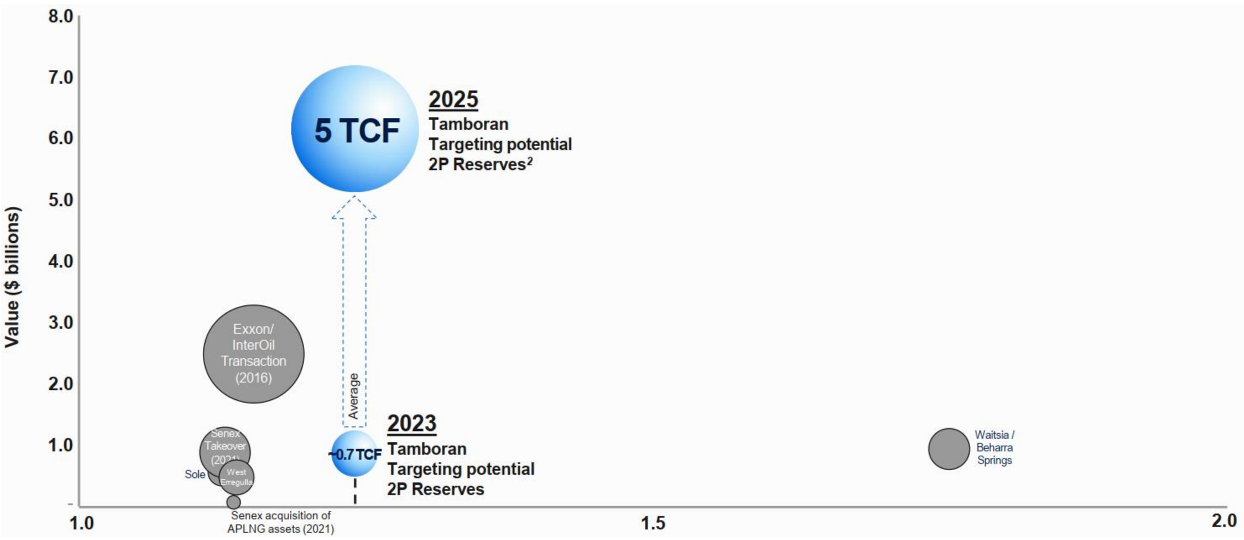
Average unit NPV10 valuation at different well costs and IP rates

		Well cost (A$mm)				
		$17.5	$20.0	$22.5	$25.0	$27.5
	2.5	0.43	0.35	0.27	0.18	0.10
IP	3.5	0.58	0.52	0.46	0.40	0.34
rate	5.5	0.73	0.69	0.65	0.61	0.57
mmcf/d	6.5	0.77	0.73	0.70	0.66	0.63
	8.0	0.81	0.78	0.75	0.72	0.70

Source: H&P estimates

Australian listing: similar playbook to Oz CBM to LNG – Australian investors are aware of the impact that unconventional gas can have on resource owners. In Queensland, once LNG trains were sanctioned at Gladstone, domestic resource owners and producers such as Queensland Gas, Pure Energy and Arrow Energy went through a sustained period of valuation increase and consolidation before being acquired by international companies such as Shell, BG and Petrochina. We see the potential for the owners of the LNG terminals at Darwin and Queensland looking to purchase volumes or assets in the Beetaloo to backfill or feed expansions to their plants. Furthermore, there have been several small cap Australian gas focused companies that have been sold in the last few years such as Warrego and Senex.

Value of deals done (A$/mcf) in comparison to the potential from Tamboran's assets

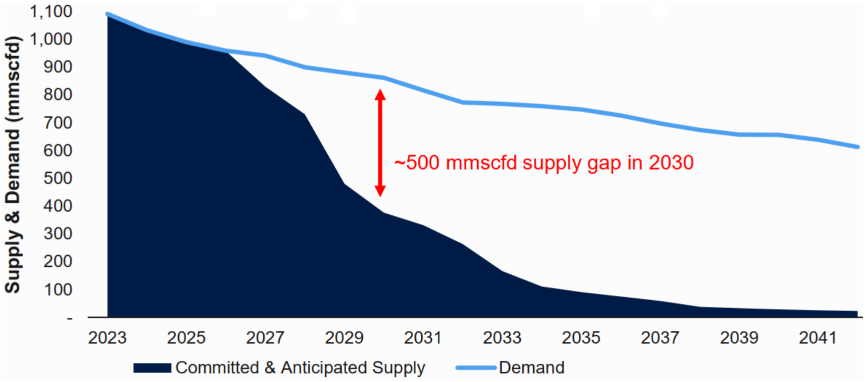


Source: Tamboran

Low/zero net carbon emission gas production - ESG is an increasingly important issue for investors in the oil and gas industry. Natural gas is an essential fuel in the energy transition away from coal. The focus is on reducing the emissions and leakage in the production of gas. Gas in the Beetaloo has been shown to date to have a lower CO2 content than the average for fields in NW Australia. Tamboran has committed to produce gas with zero Scope 1 and 2 emissions and is exploring the use of renewable energy, carbon capture and sequestration and carbon offsets. We see Tamboran aiming to sell premium priced net zero LNG in the future.

Supportive local and national Government - A key element for success in the development of a shale play is to have a supportive Government and regulatory framework. An example of the support is that the Federal Government announced A$50mm in incentives for the Beetaloo Sub-basin in December 2020. Tamboran was awarded up to $7.5 million through the Commonwealth Government's Beetaloo Cooperative Drilling Program in March 2022. The idea is to "unlock five key gas basins starting with the Beetaloo basin and the North Bowen and Galilee basin in Queensland", the government said. An Australian Competition and Consumer Commission (ACCC) report has identified the Beetaloo Basin as a priority development to address anticipated domestic gas shortfalls. Australia offers a unique combination of being a developed economy in the OECD with the ability to attract skilled labour and technology, alongside significant prospectivity. Fiscal terms are attractive on a global comparative basis: 10% royalty and 30% corporate tax rate.

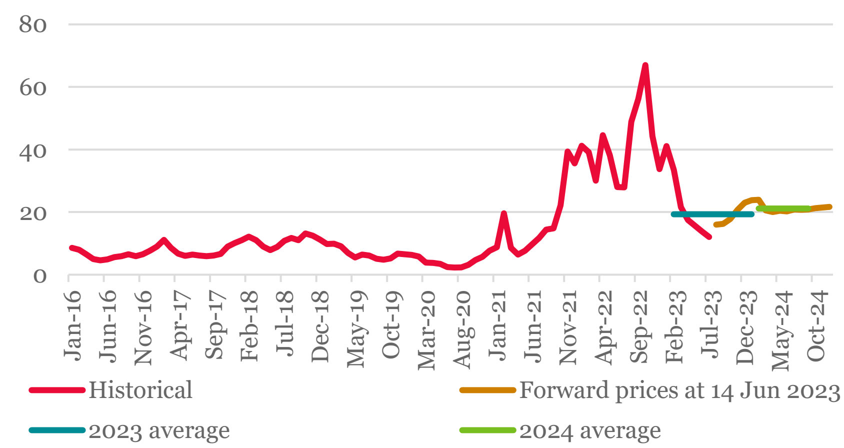
Forecast East Coast Gas Supply & Demand (assuming no gas diverted from LNG exporters)



Source: AEMO: Gas Statement of Opportunities (March 2023)

Australia becoming increasingly short gas - The growth in LNG exports has resulted in higher natural gas prices and concerns of domestic natural gas shortfalls, particularly on the east coast of Australia. The country's first LNG import facility has also been approved for NSW. The Government established the Australian Domestic Gas Security Mechanism (ADGSM) in response to fears of possible shortfalls. Development of new basins in the north, such as Beetaloo could provide the eastern and south-eastern gas systems access to large gas supplies that could produce cost-effective gas for many years. Australia's domestic gas demand has remained flat, with the only material variation being the consumption of gas in National Electricity Market gas-fired generation, which is heavily affected by both gas price and electricity conditions. Despite the lack of domestic demand growth, natural gas prices have remained high in Australia relative to other OECD countries. This indicates a lack of supply to meet local demand.

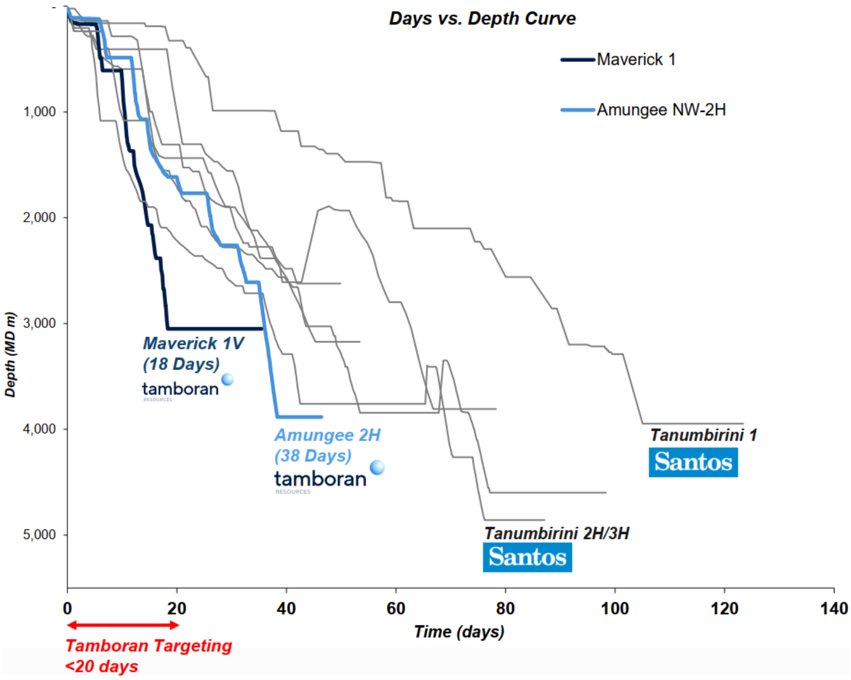
Australia historical and forward LNG netback prices (A$/GJ) at 14th June 2023



Source: ACCC, H&P estimates

Positive outlook for global gas prices, in particular Asia – We expect global gas prices to remain at attractive levels in coming years as we see gas as a key transition fuel on the path to net zero. We expect continued strong gas demand growth globally on the back of economic growth in Asia and the substitution of coal. We see global gas and LNG supply stuttering on a lack of investment caused by the last 5 plus years of underinvestment by the oil and gas industry and the delay of many planned LNG liquefaction facilities globally. This has been exacerbated by the Russian war with Ukraine, the impact of this has been gas prices reaching record levels (e.g. European gas prices and Asian LNG >US$50/mcf) well before winter 2022. Being close to high growth and high demand Asian markets such as Japan, Korea and China enables lower transport costs and therefore confers a unique benefit to the Australian LNG producers. The futures curve remains above A$20/GJ for the next few years, which is the equivalent of >US$13/mcf.

Maverick 1V and Amungee 2H drilling performance – fastest vertical and horizontal wells in Beetaloo to date



Source: Tamboran

Ability to drill effective low cost wells - A key to success in US shale plays has been drilling wells without any operational issues, using the latest technology and at the lowest possible cost. The TBN team has a strong track record of safely drilling and supervising over 5,000 horizontal wells in US shale basins over the last 10 years. Tamboran intends to leverage its extensive skill-base to reduce drilling and development costs, optimise the development footprint and mitigate environmental impacts. For example, the application of latest multilateral unconventional technology provides ability to reduce development footprint and environmental impacts. The signing of a 2-year contract for a super-spec rig, with US driller Helmrich & Payne, which will be one of Australia's most powerful onshore rigs capable of 4,000m laterals, gives Tamboran the ability to achieve best in class results. Helmrich & Payne is the largest onshore drilling solutions provider in the United States.

Valuation

300% upside to our risked NAV

Asset	Gross bcfe	Interest	Net bcfe	NPV A$/mcfe	Unrisked A$m	Unrisked A$/sh	Geological CoS	Commercial CoS	Risked A$m	Risked A$/sh
Net cash post (June '23 raise)					$84	$0.05			$84	$0.05
Capitalised G&A	@ 2x				($16)	($0.01)			($16)	($0.01)
Options proceeds					$21	$0.01			$21	$0.01
EP 98 - 100mmcf/d	1800	38.8%	698	0.48	$335	$0.19	90%	50%	$151	$0.08
EP 98 - 1bcf/d	12749	38.8%	4940	0.61	$3,021	$1.68	60%	33%	$608	$0.34
EP 136 - 0.5bcf/d	7598	100%	7598	0.51	$3,887	$2.16	25%	25%	$247	$0.14
EP 161 - 0.5bcf/d	7598	25%	1899	0.51	$972	$0.54	75%	25%	$185	$0.10
Total NAV	**29747**		**15135**		**$8,303**	**$4.62**			**$1,280**	**$0.71**

Source: H&P estimates

Our NPV10 for the development of 1.8tcf (0.7tcf net) from EP 98 is A$0.48/mcf (based on US$70/bbl flat or US$10.5/mcf Asian LNG pricing), which is worth A$0.19/sh unrisked (around in line with current share price). We use a 90% geological chance of success and a 50% chance of commercialisation to factor in development and funding risk. We see this increasing to an NPV10 of >A$0.75/mcf as Tamboran gets closer to first gas and the potential on improving on the base case well production type curve.

There is an incremental 5tcf net of potential 2P reserves that Tamboran is targeting to add to reach 1bcf/d of gross production, which we value at A$0.61/mcf, higher given the lower transportation cost to Darwin. Given the scale of this development it would be worth A$1.68/sh to Tamboran (>A$3bn) unrisked. Even risking this heavily, using a 60% geological chance of success and just a 33% chance of commercialisation gives A$0.34/sh in risked value.

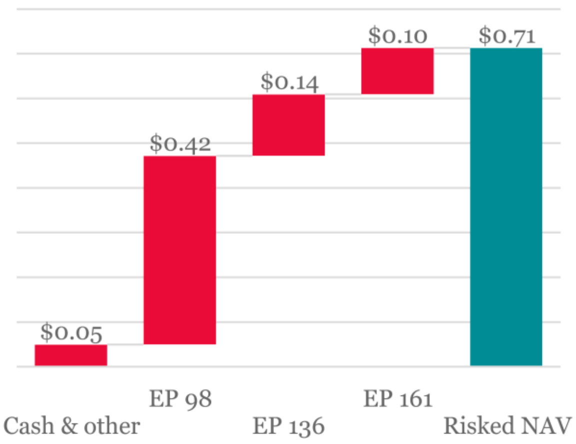
We add in a further 1bcf/d of net production of gross production based on production going to the East coast LNG plants through a new 1bcf/d pipeline. We assume 50% or 0.5bcf/d goes from TBN's 100% owned EP 136 asset (worth A$2.16/sh unrisked; A$0.14/sh risked) and the other 50% from TBN's 25% owned EP 161 acreage (worth A$0.54/sh unrisked; A$0.10/sh risked).

NAV A$/sh based on potential volume discovered & NPV of resource

		Net recoverable resource (tcf)				
		0.5	**1.0**	**2.5**	**10.0**	**30.0**
	$0.25	0.13	0.21	0.47	1.74	5.14
NPV	**$0.50**	0.21	0.38	0.89	3.44	10.2
$/mcf	**$0.75**	0.30	0.55	1.32	5.14	15.3
	$1.00	0.38	0.72	1.74	6.83	20.4
	$1.50	0.55	1.06	2.59	10.2	30.6

Source: H&P estimates

Waterfall Chart of Risked NAV by item (A$/sh)



Source: Company reports, H&P estimates

A2H well result and SS1H plans

The A2H well has not yet provided evidence of commercial flow rates and hence has been viewed as disappointing by the market, however the scale of the capital raise, the relatively low discount and the existing investor and management subscriptions demonstrates to us the company's confidence in the play and the encouragement provided by the A2H well. The well results so far have provided plenty of learnings that can be taken and used to improve the completion design of future wells.

The Amungee 2H (A2H) well in EP98 (TBN 38.75% working interest and 100% paying interest) saw a 25 stage fracture stimulation (frac) at an average of 40-metre spacing performed in the Mid-Velkerri "B Shale. The well achieved gas breakthrough and as of 23rd June, had been flowing for 50 days since the installation of production tubing, averaging 0.97 mmcsf/d. A 68/64-inch choke size is delivering at a stabilised rate of 0.83 mmscf/d, with an average flowing tubing head pressure of 65 psi and tracer data showing a good distribution of flows across the entire stimulated section. Frac fluid is being recovered during testing. The well is currently producing 65bbl/d of water with a cumulative 17,879 bbl of water recovered to date. Gas flows from the well are yet to establish 30-day initial production (IP30) rates with only ~10% of the water used in the stimulation program recovered to date.

Modelling indicates that potential skin may be inhibiting gas and water flow and the Beetaloo Joint Venture (BJV) are evaluating options to clean-up the well. TBN is evaluating potential remediation options for the third quarter of 2023. According to TBN, the initial results from the A2H well are not indicative of the underlying production potential of the Mid Velkerri 'B Shale' in the Amungee area. The gas is dry with a composition of 90.4% methane, 2.9% ethane, 4-5% CO_2 and 1.4% nitrogen.

TBN is highly encouraged that the initial results from the laboratory provide a potential pathway to cleaning up the well and delivering improved flow rates. The BJV does not believe this is a reservoir issue or that the initial results are indicative of the prospectivity of the Amungee area. The original Amungee NW1H well, located on the same pad, was determined to be flowing 1.1mmcf/d from just a 162m lateral length containing 4 frac stages, from which a normalised flow rate of 5mmmcf/d per 1,000m was estimated. The A2H well is only the sixth horizontal well drilled and stimulated to date in the Beetaloo Basin.

TBN only took over operatorship around the date of the spud in a location chosen by Origin. The Amungee 2H well was drilled and completed to Total Depth in 38 days, faster than nearby wells drilled below 2,500-metres (well designed by previous operator). There were no significant issues with the drilling or the completion of the well. Despite this the well has been flowing below the expected rates of 5mmcf/d and this is thought to be due to the formation of a "skin" that is inhibiting gas flow into the well bore. There are various theories for this that the partners are investigating but this is part and parcel of new wells in a basin. TBN expect to improve the flow rate through various clean-up activities in Q3'23.

Skin

"Skin" refers to the damaged or altered zone of the reservoir formation near the wellbore. It is a term used to describe the reduction in permeability or the impairment of fluid flow around the wellbore. Skin can be caused by various factors such as formation damage during drilling or completion operations, near-wellbore plugging, or formation fluid influx. The presence of skin can result in decreased well productivity and may require remedial treatments or techniques to restore or improve the flow of oil or gas from the reservoir into the wellbore.

Silicates and calcium-containing minerals introduced by drilling fluids can precipitate and deposit on the near-wellbore region, creating a skin that inhibits the flow of gas. To remedy this, several techniques can be employed such as acid treatments, chelating agents to dissolve and remove mineral deposits by forming stable complexes with the offending minerals, such as silicates and calcium or surfactants and dispersants can be used to modify the surface tension and wettability characteristics of the formation.

Bacteria can contribute to the formation of skin in a well through microbial-induced formation damage, when certain types of bacteria present in the reservoir or introduced during drilling operations interact with the fluids and rock formation in the wellbore. Bacterial activity can lead to the production of metabolic byproducts, such as biofilms or biogenic acids. These substances can accumulate and adhere to the formation, reducing its permeability and hindering flow, acting as a physical barrier, clogging the pore spaces and restricting fluid movement. A potential solution for this would be to pump hydrogen peroxide down the well to kill the bacteria.

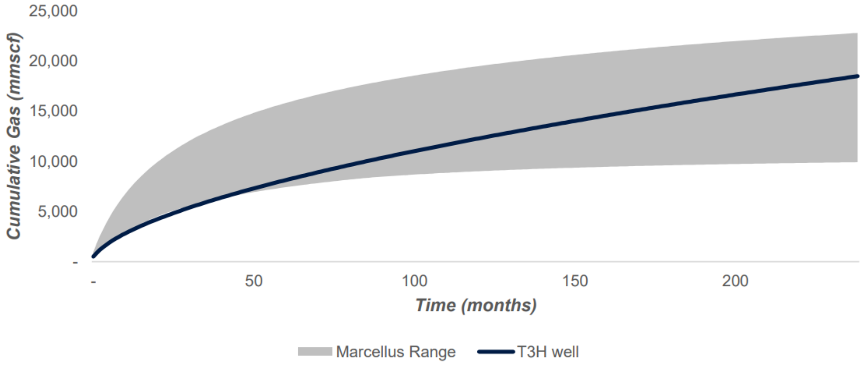
Also, the shale is highly desiccated, one of the driest in the world, which means that frac fluid will get absorbed into the shale and not flow back. A shale reservoir can undergo a process called water imbibition during the frac process: the absorption of water by the shale formation when it meets the frac fluid. The water can penetrate the shale matrix and fill the pore spaces within the rock. The imbibed water can have several effects on the shale reservoir. First, it can cause swelling of the shale rock, leading to an increase in pore pressure and changes in rock properties. This can impact the permeability of the formation and alter fluid flow characteristics. Second, the imbibed water can affect the geo-mechanical behaviour of the reservoir, potentially leading to changes in rock stability and induced stresses.

Shenandoah South 1H exploration well

The BJV plan to drill the Shenandoah South 1H (SS1H) in EP 117 during the third quarter of 2023, where the Mid Velkerri "B Shale" is expected to be approximately 700 metres (30%) deeper than at A2H. The SS1H well will complete the farm-in commitment with Falcon Oil and Gas. The decision for the SS1H well location follows analysis of the Tanumbirini wells in the Santos-operated EP 161 permit, which showed Marcellus Basin production type-curves from the wells drilled in the Tanumbirini area. Specifically, at T3H, which has demonstrated a 20-year EUR of approximately 18.5 BCF for a future proposed 3,000-metre development well. This result demonstrates the enormous productivity within the deeper regions of the Beetaloo Basin. The SS1H well IP30 flow test is planned for early 2024 and on success would allow the booking of initial 2C resource.

Modelling of Tanumbirini 2H (T2H) and 3H (T3H), which have been producing for >6 months, has demonstrated a 20-year Estimated Ultimate Recovery (EUR) of approximately 16.8 – 18.5 bcf, respectively, for a proposed ~3,000-metre development scale well. These results are in-line with the most productive regions of the Marcellus Basin, USA, one of the world's most prolific shale gas basins. The productivity of the wells, which flow tested the Mid Velkerri “B Shale” at depths of more than 3,400 metres total vertical depth (TVD), validate Tamboran's view that the ‘core’ areas of Beetaloo Basin remain the most productive and validate further testing. The results support the Beetaloo Joint Venture drilling decision of the Shenandoah South 1H (SS1H) well in EP 117.

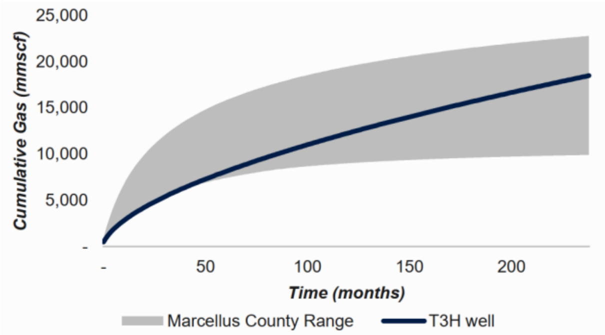
The Tanumbirini 3H well shows 20-year cumulative gas volumes in line with the Marcellus type curve set (Marcellus type curves by county – extrapolated to 3,000-metre stimulated lateral length)



Source: Tamboran

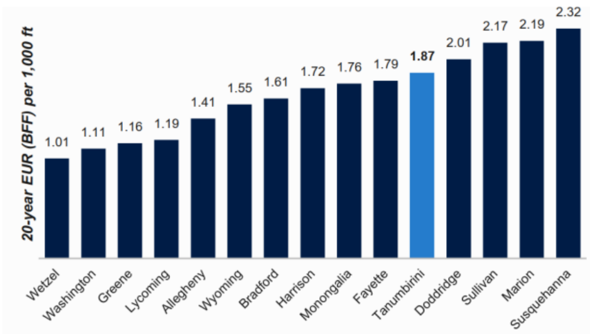
Being the first two wells drilled in the deeper 'Core' Beetaloo Basin, Tamboran believes that significant improvement in flow rate and EURs can be established with application of learnings to optimise stimulation design. The Tanumbirini wells deliver stable, long-term flow rates over a 20-year period when compared to Marcellus wells. This is a result of Beetaloo Basin wells benefiting from the large uncompetitive acreage, which support long laterals with adequate well spacing to maximise gas recoveries.

Tanumbirini wells show 20-year cumulative gas volumes



Source: Tamboran

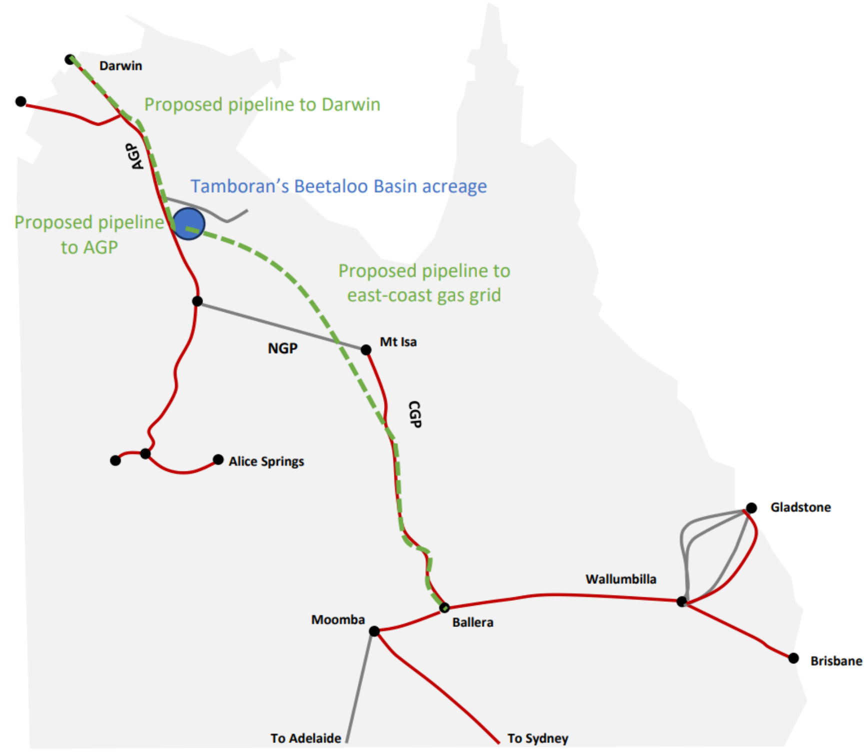
Normalised 20-year EUR (BCF per 1,000 ft)



Also, the pore pressure gradient for Tanumbirini is consistent with Marcellus dry gas counties: it is important as it directly affects the ability to extract gas from the shale formation. A higher pore pressure is generally preferable as it helps in creating and propagating fractures more effectively, counteracts the low permeability by increasing the effective stress acting on the gas within the shale and are often associated with higher gas saturation and permeability.

Infrastructure and commercialisation

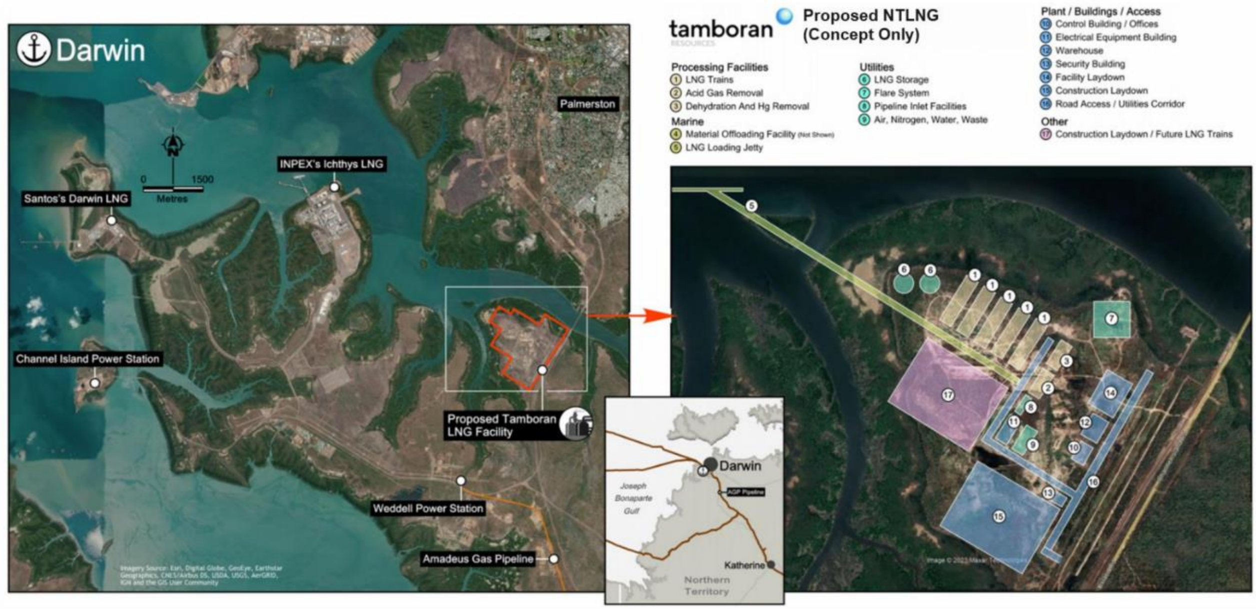
Proposed pipeline developments from the Beetaloo Basin



Source: Tamboran

TBN has for a few years been focused on the infrastructure solutions to bring Beetaloo gas to market, fully recognising that finding gas that is economic to produce is only half the challenge. TBN had signed an MOU with infrastructure company Jemena Ltd to bring the gas to market. It has now selected APA Group as the preferred transmission pipeline partner to connect the Beetaloo to both the East Coast gas market and TBN's NTLNG development in Darwin. A term sheet has been signed, planned to be converted into an agreement in the coming months in which AP will fully fund study and approval activities for the next 12 months of up to A$10mm, and it will commence a project to install a 30km gas pipeline connecting TBN's proposed pilot development at Shenandoah South (SS) to the Amadeus Gas Pipeline (AGP), targeting completion by 2025 to enable TBN to commence gas sales under the existing gas sales agreement (GSA) with Origin for 36.5PJ (100mmcf/d) of gas. APA will progress a 500mmcf/d project to connect the Beetaloo to the existing East Coast gas network by 2028. Longer term APA will also work closely with Tamboran to potentially build a 1bcf/d pipeline from the Beetaloo Basin to Middle Arm in Darwin, supplying Tamboran's proposed NTLNG development.

NTLNG



Source: Tamboran

Tamboran secures land for Northern Territory LNG Development

One of the key issues for the commercialisation of the Beetaloo is finding a market for the gas, given its remote location. Tamboran has been proactive on this front from the beginning and has secured another option for its gas. The Northern Territory Government has provided Tamboran exclusivity over 420 acres on the Middle Arm Sustainable Development Precinct for a proposed LNG development, Northern Territory LNG (NTLNG). The site is expected to host a 6.6mmtpa LNG development with expansion potential subject to completion of the Concept Select study, successful Beetaloo appraisal drilling and flow testing, and Government approvals. NTLNG would be the first integrated onshore LNG development in Northern Australia. TBN is targeting first LNG in 2030 with ~130 wells that could deliver 1bcf/d.

The Middle Arm Sustainable Development Precinct is located on a peninsula south of Darwin that already hosts the Ichthys LNG and Darwin LNG developments. The Northern Territory is working with industry and the Australian Government to accelerate the development of Middle Arm into a globally competitive, sustainable development precinct for low emissions hydrocarbon and hydrogen production, carbon capture and storage and minerals processing. This Precinct is expected to require a large, secure, low reservoir CO_2 natural gas supply.

MOU for LNG offtake with bp and Shell

An important step towards long-term commercialisation of gas from the Beetaloo is to find international buyers of the gas as in a large-scale development scenario, there is not enough domestic demand. Having offtake will allow TBN to obtain financing for the pipelines and possible LNG export plant. TBN entered into two non-binding MOUs with bp and Shell to each purchase 2.2mmpta of LNG (we estimate ~650mmcf/d of input gas required) over a 20 year period (in total ~5tcf of gas) from TBN's proposed NTLNG project at Middle Arm. bp and Shell are two of the world's largest LNG portfolio trading and energy companies and provide important and credible counterparties for Tamboran to progress financing discussions to support the sanctioning of the NTLNG project, covering two thirds of the planned output capacity. TBN will progress discussions with both bp and

Shell prior to the completion of the FEED in 2024 and aim for formal execution of the LNG Sale and Purchase Agreements (SPA) in 2025.

CEFAM's compression facility

Source: Tamboran

Framework Agreement with CEFA for gas facilities

TBN has entered into an agreement with Clean Energy Fuels Australia (CEFA) for exclusivity until end-2023 over gas compression and liquefaction facilities for early production from the Beetaloo. This could accelerate gas production and minimise flaring from appraisal wells potentially from 2024. The existing compression facilities can be expanded to utilise available capacity in either the AGP or MRP pipelines. TBN also secured exclusivity over a mini-LNG facility for four months, which could be used to supply remote communities or mines by end-2024, as a cleaner alternative to diesel. This is a significant step towards achieving first production from the Beetaloo Basin. CEFA and partners have collective experience in gas extraction, field development, virtual pipelines, fixed infrastructure and power solutions from both a market development and operations perspective.

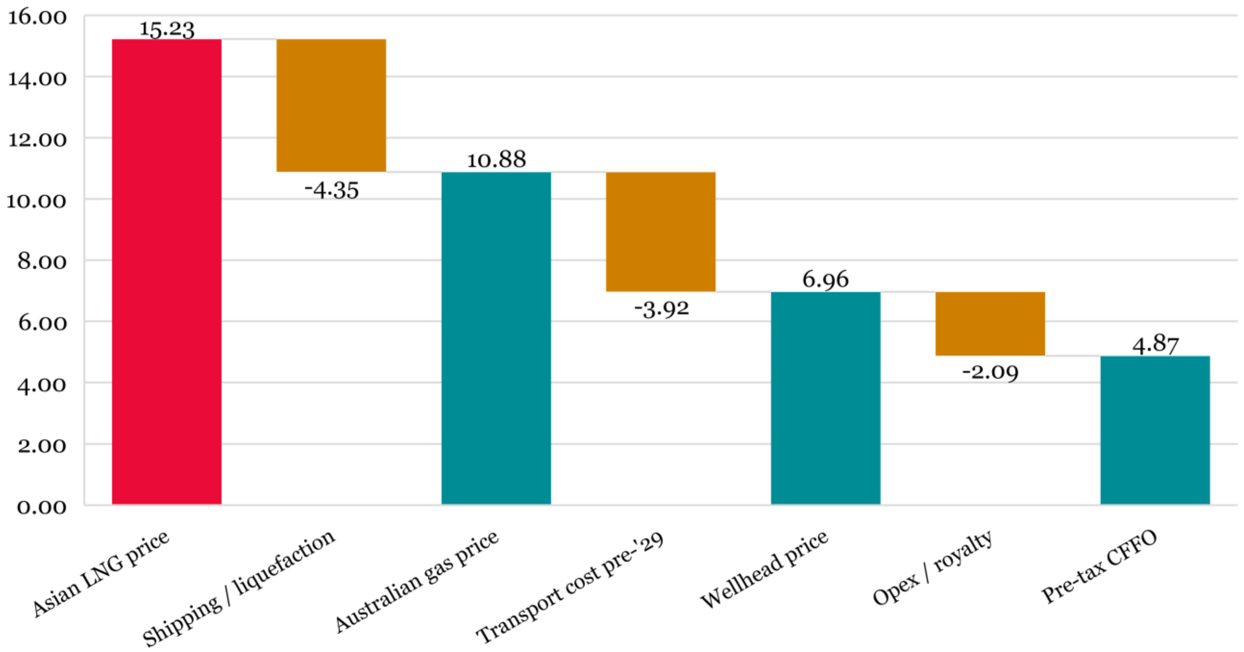
Safeguard mechanism reforms in line with scientific enquiry

The safeguard mechanism reforms passed by the Federal Parliament are generally in line with recommendations made under the independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory (the Pepper Inquiry). Tamboran believes the Beetaloo Basin's low reservoir CO_2 is an attractive source of supply for industry seeking to reduce greenhouse gas (GHG) emissions. This includes displacement of higher emitting sources of energy (i.e. coal-fired power and higher reservoir CO_2 fields) and important feedstock for the manufacturing industry. Tamboran is already targeting net zero scope 1 and 2 equity emissions from the commencement of commercial production, which will incorporate electrification of facilities and equipment, including Helmerich and Payne's super-spec FlexRig. Also, the NT Government's implementation of all 135 recommendations under the 2018 Scientific Inquiry into Hydraulic Fracturing in the NT, announced in May, provides TBN with confidence to progress its investment in the Beetaloo Basin.

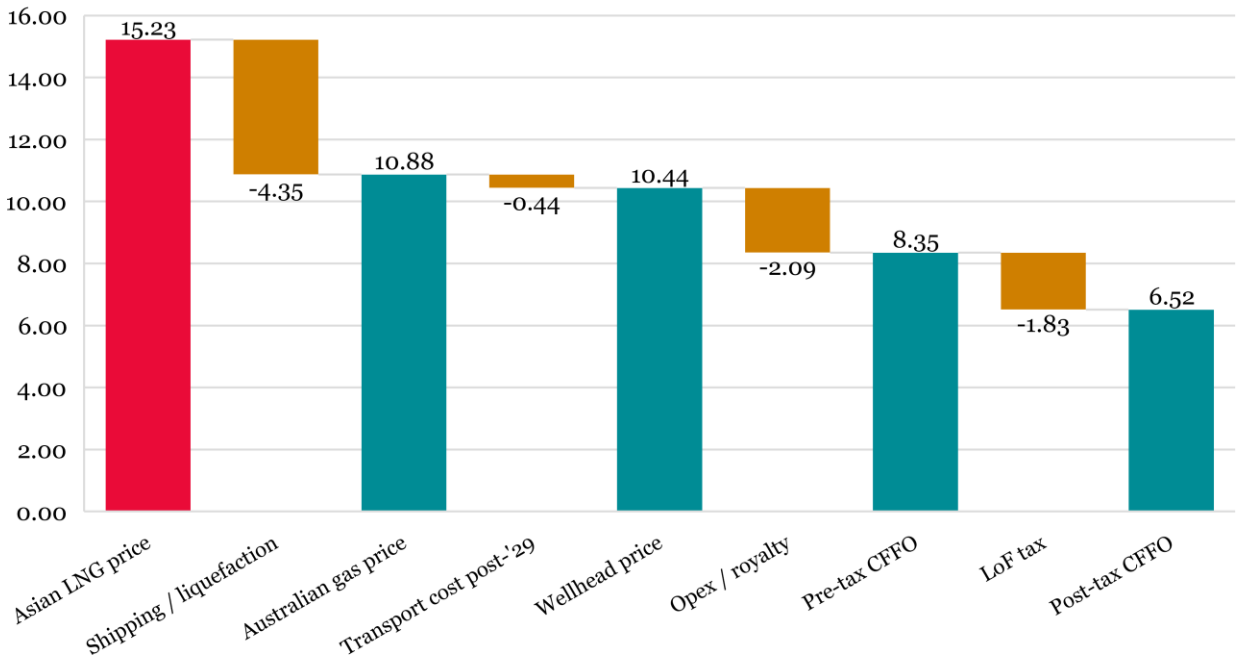
Gas prices and realised prices

The charts below show the route to the netback that Tamboran will receive based on our base case Asian LNG price of A$15.2/mcf. The top chart for the near-term assumes a higher transportation cost of A$3.9/mcf before the new pipeline infrastructure lowers costs to A$0.4/mcf from 2029. Also we assume minimal tax payable in the short term. Over the life of the field we estimate capex of A$1.5/mcf.

Split of revenue from gas sales and net back to Tamboran (pre-2029) in A$/mcf



Split of revenue from gas sales and net back to Tamboran (post-2029) in A$/mcf



Source: H&P estimates

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